COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                    )
                                     )
Preparation of the 2007 Integrated   ) Docket No.
Energy Policy Report                 ) 06-IEP-1
                                     )
             and                     )
                                     )
Implemention of Renewables Portfolio )
Standard Legislation (Public Utilities)
Code sections 381, 383.5, 399.11     ) Docket No.
through 399.15, and 445; [SB-1038],  ) 03-RPS-1078
[SB-1078]                            )
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, JULY 6, 2006

1:10 P.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

John Geesman, Associate Member

ADVISORS PRESENT

Timothy Tutt

Melissa Jones

STAFF and CONTRACTORS PRESENT

Pamela Doughman

ALSO PRESENT

John Bohn, Commissioner
Stephen St. Marie, Advisor
California Public Utilities Commission

Brian Prusnek
California Governor's Office

Ric O'Connell
Black and Veatch

Pedro Pizarro
Southern California Edison Company

Fong Wan
Pacific Gas and Electric Company

Terry Farrelly
San Diego Gas and Electric Company

Mohamed Beshir
Los Angeles Department of Water and Power

Valerie Beck
California Public Utilities Commission

Jan Hamrin
Center for Resource Solutions

ALSO PRESENT

Greg Morris
Green Power Institute

Steven Kelly
Independent Energy Producers Association

Rick Counihan
Ecos Consulting
Alliance for Retail Energy Markets

Dan Adler
California Clean Energy Fund

Nancy Rader
California Wind Energy Association

Doug Wickizer
California Department of Forestry and Fire Protection

V. John White
Center for Energy Efficiency and Renewable Technologies

Cliff Chen
Union of Concerned Scientists

Jeff Lam
Powerex

Juan Sandoval
Imperial Irrigation District

John Galloway
Union of Concerned Scientists

Bob Burton
Insulation Contractors Association

David Withrow
Robin Smutny-Jones
Dave Hawkins
California Independent System Operator

Jim Avery
San Diego Gas and Electric Company

ALSO PRESENT

Rich Ferguson
Center for Energy Efficiency and Renewable Technologies

Greg Morris
GPI

Kevin Dasso
Pacific Gas and Electric Company

Gilbert Tam
Southern California Edison Company

Tony Braun
California Municipal Utilities Association

I N D E X

P R O C E E D I N G S

1:10 a.m.

ASSOCIATE MEMBER GEESMAN: I want to welcome all of you to our workshop today. Commissioner Pfannenstiel will be joining us shortly. She's been called away to a transmission operations meeting in the Governor's Office.

This is a Committee workshop for the Energy Commission's Integrated Energy Policy Report Committee. I'm John Geesman, the Associate Member of that Committee.

We're joined today, and hopefully will be throughout this year's IEPR cycle, by Commissioner John Bohn from the Public Utilities Commission.

Our purpose is to conduct, over the course of the next several months, the mid-course review that the Energy Commission's Integrated Energy Policy Report adopted last November recommended for the RPS program.

I think the RPS program obviously has a lot of interest, based on the attendance today. I'm sure that you're aware of that. The Energy Commission's 2005 IEPR expressed concern as to whether or not we were on a trajectory to achieve the 2010 goals that had been set for the program.

I think there are a lot of different perspectives to be taken to whether we're on that trajectory or not; what the appropriate structuring of the program should be. I want to encourage as much diversity of viewpoint and candor as we can muster today.

I think we're probably all united, and I know both Commissions certainly are, in the desirability of meeting those goals. And if the program needs some recalibration or reorientation to better equip us to do so, that's our objective.

So, you're likely to hear some critical comments, because I'm here some caustic comments, but I think what does unite all of us is a desire to see the program succeed, and to achieve what are, in fact, the most aggressive goals for renewable energy set anywhere in the United States.

Commissioner Bohn, do you have anything to open with?

COMMISSIONER BOHN: Thank you, John. Just a couple of comments. I would certainly concur in what Commissioner Geesman said.

This is a complex process. We're making

progress. There are a number of obstacles yet to deal with. And we're working through them. And I want to thank all of you here today for your comments and criticisms and suggestions not only today, but going forward.

I think we are united in the objectives. I think there's some really knotty kinds of issues as to what the best way to achieve those objectives would be. And I would also encourage candor. I may not be as caustic as Commissioner Geesman, but I like to think that we will be as interested and as focused on getting real answers as Commissioner Geesman and his colleagues will be. Thank you.

MS. DOUGHMAN: I need to give you just a few housekeeping items before we begin. For those who are not familiar with this building, the closest restrooms are located over this direction. There's a snack bar on the second floor.

Lastly, in the event of an emergency and the building is evacuated, please follow our employees to the appropriate exits. We will convene at Roosevelt Park located diagonally across the street from this building. Thank you.

And, Ric O'Connell.

MR. O'CONNELL: Thanks, Pam. Thanks, Commissioner Geesman, Commissioner Bohn. I'm in the unenviable position of presenting a lot of other people's work. So, I'm just here to sort of set the stage, if you like. I'm feeling deja vu, I did this last week, as well, at the credit requirements workshop that was held.

And just give you briefly, and luckily, because I don't know a lot about these topics, it will be brief, what's been going on in the last year. I'm going to brief to you three contractor reports; take a look at some of their recent IOU contracting efforts. And look at some of the other issues we'll be delving into in more depth today.

So the first report I'm going to talk about is the preliminary stakeholder evaluation. This report came out in about August of 2005. It was highly recommended. I can't do it justice in the two slides that I have to talk about it.

There's 21 stakeholder interviews. It looked at sort of the overall design and the process of the RPS. Some experience with IOU contracting which we're going to talk about. Some of the deliverability rules. And then generally the report findings.

And I think all of this is summarized in one of the reports that's out there, that the RPS, like the state, is unique in its design and complexity. Implementation has been slow, however, I mean, I think to be fair, you know, the IOU contracting efforts have been spinning up. You know, RPS has really only been in place for a short time.

There's a lot of everybody seems to agree that there's challenges and problems. No one seems to agree how to fix them.

The next report is one that I actually did work on. This is the building of margin of safety or the contract failure report. And in this report we looked at historical experience in California with QF contracts, the turn of the century CEC incentive options, some of the earlier RPS contracting.

We also looked at about 3000 megawatts of contracts from 21 North American utilities in the last couple of years. And then we looked at some auctions and other contracting efforts in places like France, the U.K., Massachusetts and New York.

So I'm sorry for the small type, but our findings were that really at minimum you should expect a contract failure rate of 20 to 30 percent. However, we really found it very difficult to see sort of a uniform contract failure rate. I mean there were some utilities that had no contract failure; there were some that 100 percent.

And all the reasons, and there's many many reasons that contracts fail, all of which really apply in California to things like siting, transmission, permitting.

So we had some recommendations in that report. And the recent PUC Matson decision. I think the PUC declined to sort of mandate a quote-unquote "margin of safety". But IOUs are taking their own sort of steps to mitigate contract failure.

The third report was the publicly owned utility. I think there was a feeling among many stakeholders that sort of the POUs were a little bit behind the IOUs in their efforts towards renewables. And I think this report kind of, you know, laid that issue to rest in many ways.

You know, obviously POUs have different

targets; they may have different deliverability rules, resource eligibility rules. But in many ways the POU -- the RPS targets are more aggressive than IOU targets. And I think it's pretty interesting that about 98 percent of the total load, those publicly owned utilities, folks like LADWP and SMUD, have established RPS targets.

There's been some recent activity. LADWP just announced a contract from some wind in Wyoming. So obviously we have deliverability going on there. And I think Silicon Valley also has some contracting. And I think all told, about 1000 megawatts of renewables are under contract to publicly owned utilities in the state.

So just to get you up to date on the recent contracting efforts from the three IOUs, about 2500 to 4000 megawatts of new capacity has been under contract. It's about 69 percent of the 2004 load. Obviously we're still waiting to see in contracts from Edison and San Diego Gas and Electric from their 2005 and obviously 2006 RFOs are just coming out now.

There's still just a small amount of, this is actually in operation, about 240 megawatts. So, even though there's a lot of contracts, there hasn't been a lot of operational projects, and I think we'll see some more projects coming online.

And I apologize that this graph really didn't come out very well in the printout. But this just sort of shows the range of each of the IOUs from a -- I think a lot of this is from the Sterling, the SES contracts that have, you know, sort of a 500 to 800 megawatt buildout.

And this graph didn't come out at all on the printout. And that's because it's secret data.

And this is just showing what we see as quote-unquote "contract failure" within the RPS contracting to date. And Edison has that big red bar of delayed, and I think that's because of their announcement that a lot of their projects, especially in the Tehachapi area, are going to be delayed because of transmission. But you can see that there's just sort of a small amount of projects actually online.

And we also looked at the RFO timelines. This is the number of months between the release of the RFO and the first advice letter filing. So we can see that timeline started out pretty high around sort of 10 to 19 months for 2003, 2004 RFOs. But things have gotten quicker. We're sort of at eight-plus months, eight or nine months for 2005 and everybody's goal for 2006 is five months. So it seems like the process is getting more streamlined; the procurement process is moving quicker.

I'm not going to talk to you much about transmission because I think we're going to go into depth into that today. But I think most people agree, it seems to be one of the biggest barrier to meeting RPS goals. The ISO is here today and is going to be speaking on that.

And, of course, the PUC has done some important work on that. Some, you know, backstop cost recovery, recent, and some other things. So we're going to talk about this more today.

Deliverability. One of the recommendations from the stakeholder report was to loosen deliverability requirements. And I think in the 2005 RFOs that extended from IOU service territory to the entire ISO. And in 2006 that went to the entire California grid, though we're not quite sure what that means.

The CEC has done some clarification of

out-of-state delivery. And then the PUC has opened a proceeding on RECs. So, there's things happening in this.

Everybody wants to know about WREGIS. So, WREGIS is moving forward. The CEC is right now using an interim tracking system. WREGIS is sort of a collaborative effort with WECC and the Western Governors Association. There was a recent RFP. I think the latest update is -- yes, it's here on the slide, notification of intent to award in July. So WREGIS is moving forward, which is good. And will obviously help with RECs and deliverability issues.

Transparency. In the 2005 IEPR stakeholders talked about transparency as being an issue in the RFO process and the RPS process. The recent Matson decision actually asked utilities to report more clearly on their evaluation criteria, and also to have an independent evaluator. So we'll be talking, I think, more about these issues today.

The market price referent and SEPs. The stakeholder report actually recommended having an escrow account. One of the concerns that many developers have is that SEPs aren't going to be bankable and you're not going to be able to finance a project based on SEP income stream. That hasn't happened.

And there was also the more sort of provocative recommendation to just abolish the whole MPR and SEP issue together. So I don't know if we'll be going down, talking about that today.

But, you know, the MPR methodology did change this year. There's no longer a proxy peaker unit. There's now time of delivery based on the baseload. The MPRs for 2005 are around $80. So we'll be, I'm sure, addressing more of these issues later on.

And there's other issues, if you want to take a look at the report that was prepared for this workshop. We sort of talk about some of these other issues like who owns RECs for distributed generation; you know, how compliance reporting is done; how -- you know, some more issues on contract failure.

I'm not sure if there are going to be any conclusions from me, because this is more for what's going to happen today. But I think everyone agrees that reaching 20 percent due to transmission and other challenges is going to be quite difficult.

There still needs to obviously be some kind of compliance for all the other small little folks, not just IOUs and POUs. And so I think it's good that we have both the PUC and the CEC here today in this workshop. And so hopefully we'll be able to work through some of these significant issues.

Thanks very much.

MS. DOUGHMAN: Okay, we now will move on to some summaries from the investor-owned utilities and Los Angeles Department of Water and Power regarding RPS progress and issues.

The first on the agenda is Pedro Pizarro. You can either speak -- come up here, or from the table, whichever you prefer.

MR. PIZARRO: (inaudible).

MS. DOUGHMAN: Okay.

MR. PIZARRO: Well, good afternoon, Commissioners and everybody in attendance. Wanted to thank you for the opportunity to speak about this important topic. And I'm glad to see this type of joint interaction among both the PUC and the CEC.

We at SCE, I think, as you know, are

working very hard to achieve the 20 percent renewables target by 2010. We've been upfront about the fact that there are some challenges to that. And we expect that we'll have sufficient energy under contract. But the question is whether or not there'll be sufficient energy actually delivering by the 2010 timeframe.

And I think the issues that will be discussed here today cut to some of the challenges that we all have in meeting the renewable procurement standard.

But on the SCE side we have increased our staff and we're continuing to add resources to handle our extensive renewable procurement activities. This is a large and complex undertaking, and one that we take very seriously.

In 2005 SCE purchased or produced nearly 13,000 gigawatt hours of renewable power. And that was around 17.2 percent of our bundled retail sales.

We buy more renewable energy than any other utility in the country, or frankly than any other state in the country. And we buy something like one-sixth of all renewable kilowatt hours in the United States.

We completed our 2002 and 2003 solicitation successfully, signing 13 contracts with renewable projects. And those contracts will deliver somewhere between 960 and 1700 megawatts of capacity. The 960 are the initial deliveries, and we have options for up to 1700.

Now, those 13 contracts, 11 of them are with new projects, delivering new, new steel in the ground. And that's expected to yield 700 to 1500 megawatts. We are very committed to taking every reasonable action to get these projects operational. We're monitoring them very hard through our contract administration activities. And we want them up and running as soon as possible, delivering kilowatt hours and spinning the meter.

And we are currently finalizing negotiations with our short list of bidders from our 2005 solicitation. We expect to complete those contracts and have them in front of the PUC in this quarter. And we also expect to launch our 2006 solicitation a week from tomorrow. So there's a lot going on and will continue to be a lot going on.

Meanwhile, on the CPUC side we have to

acknowledge that there's been just a tremendous amount of work in partnership with the CEC and other agencies to diligently implement the renewable portfolio standard. And if I have a single message for today it is that this is, again, a massive undertaking. I think all the pieces are in place. There are some course corrections, but overall we need to stay the course in order to let the program work, and the utilities and other parties do the contracting to achieve the goals of the program.

The PUC has issued more than 15 decisions; more than 11 rulings and three proceedings to implement various aspects of the renewable portfolio standard. And so really now is the time to allow these orders to be implemented to see how well they will work. And abandoning these efforts by making major mid-stream changes, as opposed to course corrections, will only delay progress towards the state goals.

Now, at SCE we are also taking independent actions to facilitate renewable development. We are seeking developer input so that we can find, quote-unquote, "the next Tehachapi." That is, finding other areas where renewable projects are likely to be developed if transmission is built. And having upfront visibility to where those areas are will help us in our planning efforts, and particularly with transmission.

Now, in order to try to stimulate greater response from renewable developers and a more rapid contracting process -- and we acknowledge that the process has been slow initially; it's sped up and we'd like to see continued fine-tuning of that -- we are evaluating revisions to our contract terms and conditions.

And we sought and have received tremendous amount of valuable input from bidders individually. We've received it through our workshop that we held in May with a number of potential bidders. And most recently the workshop in this very room last week on contracting and credit issues was a very helpful exercise. We've already taken some of those input to heart and expect to be pushing some changes in our terms and conditions.

Now, we are also pushing very hard to develop the Tehachapi transmission project, with the first segment expected to be online by the end of 2008; and more segments and phases through the following years.

We're also working with regulators and with the ISO to improve the interconnection process and to facilitate the development of needed transmission.

Some examples. In 2005 we sought authority for a renewable trunkline process at FERC. Unfortunately, FERC rejected our proposal, but we were very heartened last week when we saw that the ISO whitepaper that came out promises to reconsider this type of structure. And we think it is a good balancing out, allowing the development of these trunklines to areas that are renewable-rich areas.

We also filed an advice letter 1950 at the PUC. And we gained, through that advice letter, CPUC authority to fund interconnection and environmental studies for renewable projects that have contracts in hand. And that avoided a one-year delay in the regulatory approval process, which is a great thing in order to expedite the process.

We're also advancing the cost of transmission interconnection studies and environmental studies, again for projects with contracts. And continuing to look for ways to improve and expedite the whole renewable procurement process.

We're also providing some ideas to the PUC and others on how to improve some of the ancillary processes like the permit-granting process. Looking for ways to eliminate duplication of activities and expedite the overall approach.

So, a lot has taken place. We've made some good progress. There's more work that needs to be done, both by ourselves, by other load-serving entities and by the PUC, CEC and the ISO. But we think that the program is ontrack. We know there's some challenges out there. We're working on them. We need to continue to work on them, but we need to stay the course.

And finally, to say we are very eager to listen to new ideas and that's why we look forward to the rest of the workshop today.

Thank you.

ASSOCIATE MEMBER GEESMAN: Pedro, thank you for your remarks. The PUC, in the May decision that was issued, and I think it was earlier referred to as the Matson decision -- as a Commissioner it's little hard for me to understand how an ALJ gets his name on a decision unanimously adopted by the Commission, but I'll call it the Matson decision nevertheless -- pretty clearly articulated the philosophy that they are going to take to the program.

And I think in a way that has a clarity that I've not seen since the original June of 2003 decision launching the program. And they said that they were going to give the utilities considerable business discretion in determining what types of technologies to pursue, what types of contracts to sign.

But that despite an effort on the part of some of the IOUs to equivocate as to whether the goal was deliver gigawatt hours in 2010 or simply sign contracts in 2010.

The CPUC reaffirmed that that goal is deliver gigawatt hours. And they made very clear that if the utilities are incapable of meeting that goal, there will be adverse consequences.

Do you feel comfortable taking on that responsibility when you recommend that we simply stay the course?

MR. PIZARRO: Well, we -- the answer is yes, we do have the responsibility to take on appropriate action so that we can move our customer portfolios to the 20 percent target.

In terms of the decision you're correct in quoting it. The decision -- point out a couple of other elements. We, and I think PG&E also, had asked for the Commission to provide some upfront guidance on what flexible compliance would mean.

And clearly that's a big issue for us, because as we're going out to the market and signing contracts, and there are a lot of moving pieces, and it may be that some of these signed contracts may come in late, be delayed, et cetera.

And so we want the ability to demonstrate to the PUC that we made our best efforts to meet those targets. And to the extent that in spite of our best efforts, situations have occurred that prevent us from actually having sufficient electrons spinning the meter by 2010. We want the chance to make our case at the PUC and have the flexible compliance.

We had asked for more of that guidance upfront. I think what the decision said was they were not going to define that upfront, but there is still that door open. And I think that's also codified in the statute that launched the renewables program.

There's also, and I think this is a key point, I think it's important that the market, as a whole, understand the depth of our commitment to the renewables program, and the fact that although this is not an area where we profit directly, there is a potential for significant penalties. And that is an excellent incentive to make sure that we are doing all we can to contract.

But we balance that by making sure that as we go in and contract we are entering into deals that make sense for our customers, that present a good package of terms, conditions and pricing. And we really want to resist the potential downside here of in order to avoid penalties in any cost, signing up customers for contracts at any cost.

And so we really think that the flexible compliance notion, even if it hasn't been defined upfront by the PUC, will be important to us in the back-end, because we want to demonstrate with check-in points all along the process that we're signing contracts that present an appropriate balance of risks and rewards for our customers; and that we've done all these things rights and things happen, and we still don't have 20 percent of electrons spinning our meters in 2010.

We want the chance to be able to demonstrate to the PUC how our efforts were there and why it happened, and why there might be a good case for excusing us from any specific penalties.

So, a long way to answer your question, John. You know, we do accept the responsibility to an active program. We like more comfort upfront, but how we can get flexible compliance, sure. But do we respect what the PUC is doing and willing to roll up our sleeves and work with them and with you, absolutely.

ASSOCIATE MEMBER GEESMAN: Thank you.

MS. DOUGHMAN: Our next summary is from Fong Wan of PG&E.

MR. WAN: PG&E appreciates the opportunity to come to the CEC and the CPUC today. The first thing I want to say upfront is that PG&E's extremely committed to the state's RPS program. If there's any uncertainty to reach 20 percent, it would be due to the timing realities of new plants and transmission.

Similar to Pedro's remarks, PG&E believes that the RPS program's on track and we would recommend that the IOUs be allowed time to get the program to work.

Can you turn the light down so that everyone can see. Thanks.

Pedro gave his little promotion about how clean their portfolio is. PG&E also believes our portfolio is very diverse and climate friendly. We have among the lowest GHG emission rating in California, as well as the nation.

Approximately 54 percent, you can see the pie chart on the left side shows that we get our power from carbon-free resources. We have assumed that the other side is all fossil, but we do not know for sure if all is fossil, because some of those are DWR contracts, as well as open-market purchases.

In terms of the 54 percent I want to say that 23 percent does come from nuclear. And another 19 percent comes from large hydro, which we believe is also renewable power, but it's not RPS eligible.

In terms of what's RPS eligible is the four little slices that you see that amounts to about 12 percent. We believe overall we have over 30 percent in renewable power in our portfolio.

In terms of our progress to date, I mentioned we are 12 percent. In the 2004 RFO we signed 2.3 percent. In '05 RFO we have already signed 1 percent. We're targeting 2 to 4 percent. That should amount to, by the end of the '05 RFO, to 16 or 17, maybe even 18 percent. PG&E also issued our '06 RFO June 30th, two days after the CPUC decision.

A little breakdown of what is it that we have. You can see from this chart overall that we have a lot of different contracts, a lot of different technologies. Our 2002 interim procurement RFO allowed us to contract 113 megawatts. We signed some bilaterals in '03 for 69 megawatts.

We really started our full-out effort in 2004. That's the year that PG&E exited from bankruptcy. While we were in bankruptcy it was difficult for us to sign long-term contracts.

So in the '04 timeframe we signed 350 megawatts; you can see the delivery date on the right. Most of those have not been delivered. It does take time for developers to get their financing, to get their equipment, get their construction. And one project has come online.

We also in '05 had some more bilaterals. And in terms of the '05 RPS RFO we already have three projects signed. The next amounting to 100 to 165 megawatts should be signed this month. We're hoping to sign another 200 megawatts in the third quarter of this year. So that's our game plan.

This is the next page. There are two lines on this graph. It's really an illustration for 2005 RFO. What I want to point out to everyone is that transmission is a critical issue for developing renewables. The way to read this graph is on the vertical axis is dollars per megawatt hour; horizontal axis would be cumulative gigawatt hours. So all this is, is a price and quantity curve.

The line on the right side represents an illustration of all the RFO offers we receive regardless of transmission constraints. The one on the left reflects not constrained by transmission. So you can see at least half the quantities are constrained by transmission. And would require -- there's a timing concern here.

We also have done some things while in the '05 RPS RFO. We have increased our outreach effort. We have received a 100 percent increase in offers; 250 percent in volume. And we have almost every single technology one can think of. The majority of the bidders are new participants. And, again, what we learned is project lead times are lengthy; roughly in the two- to three-year period. And we also saw significant responses from SP-15 and the Pacific Northwest.

I'd like to quickly cover what has gone right, and some of the things that we will also need help on.

In terms of what has gone right, we talked about the developer turnout. I think what's really eye-opening is that the offers show where the transmission should be built. We're not looking at research or academic studies any more. We're looking at real commercial offers in terms of our transmission planning.

We talked last week about the bid deposits in this room. We've also expanded delivery points beyond our service territory and out of state. We have thought of some creative commercial solutions on transmission upgrades.

And we also believe that the CPUC made significant improvement in the NPR timing and process.

The CEC Staff also have put in lots of work to create and update the RPS program guidebooks, including the RPS tracking and verification methodologies.

We talked a little earlier about the CPUC and the ISO efforts on transmission development. And we believe that we also have a very robust evaluation process where the procurement review group has been very collaborative and provided lots of input into our processes. And we have been using an independent evaluator to verify the evaluations; to also put integrity into the process; and answer any questions that PRG may have. And the independent evaluators may also be used for testifying at the CPUC or at the CEC if that's appropriate.

We also believe that the CPUC has done significant work in terms of protecting confidential information. We believe this is extremely critical, after all, all of us in America is after capitalism, we like to make as much money as possible, price it as high as possible. So we don't believe having all the information out in public is in the best interests of our customers.

The last part is that we believe that all the foundation has been laid out by the two Commissions. We believe the RPS program is ready to take off for success.

In terms of some of the areas that we could use some help. The first one has to do with what we call shaping and banking for out-of-state intermittent projects. that's just another way to describe wind.

We have found there's significant wind possibilities outside of California, as well as inside of California. And wind resources outside of California has different challenges than within California because of the scheduling requirements into the ISO. That it requires planning, which makes the wind resources very difficult to do.

Within the State of California the Cal-ISO has a special program for wind. It's called PIRP. I can't remember what it stands for, but it is a program that allows the wind to come online.

And what we would like to do is that we would like to submit some contracts to the CPUC and to the CEC to get clarity on this issue in terms of how out-of-state wind projects can work. And that should be happening this year.

The second topic has to do with SEP finance-ability. Several sellers have told us that in other states, not in the State of California, that SEP were granted but not honored during the course of the contract. And that has presented significant challenges for the financing of these projects.

What the sellers have asked us to request is that the CEC would consider separate escrows such that the money cannot be called back during the delivery timeframe of the contracts. So it is something that supposedly has happened in other states.

ASSOCIATE MEMBER GEESMAN: Let me jump in and address that, Fong, because that did come up at an earlier workshop that Commissioner Pfannenstiel and I held on our renewable guidebooks.

And both Commissioner Pfannenstiel and I are supportive of that, and recognize the need for it. I will say the State Department of Finance, for the very reasons that we think it's a good idea, and I think the market thinks it's a necessary idea, the State Department of Finance is reluctant to let go of control of the money.

Now we have provided language to various would-be legislative authors. I'm not aware of anything being put in legislative form yet. But the appropriate forum for that, which I think is a very good idea, is to put an amendment in a bill and get a third-party escrow capability established. I'm skeptical that any of these SEPs will turn out to be financeable without that.

MR. WAN: Thank you, I agree with that.

COMMISSIONER BOHN: Can I just ask a question, John, really to you? Do you need legislation for this? I mean, escrow's a common process.

ASSOCIATE MEMBER GEESMAN: Unfortunately you do in order to get the money out of the State Treasury. And the Department of Finance would like it to stay in State Treasury in case of adverse conditions down the road call for the ability to borrow that money for awhile.

But that's why a lender will not consider the SEP financeable. And we do need a separate statutory capability to establish that.

MR. WAN: Yeah, I think this issue is

fairly critical for us because we do have one contract for an '04 solicitation in front of the PUC which needs some amendment. But that contract does need SEP payments. I believe San Diego also has one.

So the certainty of the SEP payments will turn out to be possibly a deal-breaker for the sellers.

ASSOCIATE MEMBER GEESMAN: Well, a lot of the people in the room have much better friendships with Members of the Legislature than I do --

MR. WAN: Okay.

ASSOCIATE MEMBER GEESMAN: -- so I would encourage you to take that up. And I will volunteer individually to testify on behalf of it.

MR. WAN: Okay.

ASSOCIATE MEMBER GEESMAN: Do not anticipate the Department of Finance being supportive, though.

MR. WAN: Okay, I understand that. I will tell you, John, I've also talked to the Governor's Office about this issue. So,--

ASSOCIATE MEMBER GEESMAN: I think they understand it.

MR. WAN: Yes, they do. So, it's going to need a full court press from everybody in the room.

ASSOCIATE MEMBER GEESMAN: Yeah.

MR. WAN: We talked about the transmission issues already; that needs to be continued to be refined.

The last part, and this is somewhat similar to the second part; this is dealing with the federal government, which is the certainty of PTCs and ITCs. A lot of the sellers are telling us that they can't absorb the risk of whether the production tax credits and investment tax credits will be extended. So any effort from people in this room who can offer will be much appreciated.

And the last part is that we believe that a common RPS standard should apply to all load-serving entities. Some of us may not realize this, but 40 percent of the load is not served by the three of us. Thirty percent or so are by the munis; 10 percent by the ESPs. After all, we are one state. We have a state goal to be a leader in renewables. And we'd like to see that be applied to everyone.

ASSOCIATE MEMBER GEESMAN: Let me ask

you, a lot of us have invested a fair amount of expectation in the policy articulated by the CPUC in their December 2004 long-term procurement decision that renewable projects were to be a rebuttable presumption for all long-term procurement.

Your company conducted the first solicitation that's been done under that 2004 decision. I believe you elicited 50 different responses to your RFO, but not a single one of them was from a renewable project.

I and others characterized that as an abject failure. Is that all-source procurement mechanism a usable device to encourage more renewable projects? Or are we really best off focusing exclusively on the RPS solicitations?

MR. WAN: John, you are correct; we received over 50 offers and did not, to the best of my recollection, receive any renewable offers.

And the details of that RFO was that we were looking -- PG&E was looking for dispatchable and peaking power. And the reason we were looking for that is we followed the state's preferred loading order of customer energy efficiency, demand response, distributed generation and renewable. And the last part that we need, in terms of our resource mix, would be the type of power that can respond to our customers' summer afternoon demands when the load ramps really hard.

So we were looking for specific capability from the resources, or the offers. It was open to any possibilities. So if there were some possibly solar projects that may be able to meet that need, but we did not receive any of those offers.

I do not consider that solicitation to be a failure. I think we should continue to keep the option for the renewables to bid into the all-source RFO.

ASSOCIATE MEMBER GEESMAN: Thank you.

COMMISSIONER BOHN: May I just ask a question here. I was under the impression that all the rest of these folks were subject to the RPS standards, and you referred to something called common standards.

Is there code talk going on that I'm missing somewhere? I mean isn't everybody subject to whatever these standards are?

MR. WAN: Well, I can talk about the questions I have about potentially some of the muni purchases. I think we have an LA speaker here today.

Their out-of-state wind project, for example, I would like to understand how can it be scheduled into the state. How can it be banked? Are they under the same rules as we are per the CPUC and the CEC? For example.

COMMISSIONER BOHN: So, your issue is, when you say common standards, your issue is subject to the same rules or subject to analogous rules or, I mean, being a big utility and being a little bitty producer doesn't lend itself to having the same sort of agonizing stuff that the government lays on you guys.

Is there an issue here about specific application of specific rules that's underlying what you said? Or am I just implying something into it?

MR. PIZARRO: Maybe if I could jump in here. I start with the statute of SB-1078, which says that the PUC -- and I'm paraphrasing here -- will develop common standards for all their jurisdictional entities. And then the municipals, the publicly owned utilities, I think are encouraged to meet the Legislature's intent.

So, right there from the start in SB-1078 there is a difference between the PUC jurisdictional and those who are not.

Like Fong, I agree that an ideal for the state would be -- and this would require legislation -- to move to a common platform for everybody where we all have the same requirements.

For example, if the requirement is to have up to 20-year contracts, or to incentivize new generation or what-have-you, that should be applied equally.

Focusing on the CPUC jurisdictional tract, though, we do have, as you know, very full implementation of the requirement for the utilities. I think the PUC is still acting, has yet to fully act on the requirements for ESPs and multijurisdictional entities. So, today we don't have a full implementation of the statute at the PUC for ESPs.

And as I understand some of the ideas being discussed right now there is this notion of a different requirement. For example, looking at allowing contracts less than ten years. One the one hand I can understanding why that comes up, because of the smaller entities. But on the other hand, we've seen in other areas like resource adequacy that the PUC is being very deliberate in insuring that it's applying the same sort of requirements, because those have ultimately a cost to them. Applying the same requirements to everybody so that there's a level playing field.

I think AB-380, signed by the Governor last year, also has very explicit language that says that the same requirements need to be applied to all entities in the PUC's jurisdiction.

So that's the area where we're seeing that there has not been a full implementation of the statutes. And today there is not a common set of rules that applies to everyone.

MS. DOUGHMAN: Okay, our next speaker is Terry Farrelly from San Diego Gas and Electric.

MS. FARRELLY: Thank you, and thank you for the invitation to be here today. I just want to say that I feel that SDG&E has made great progress in our renewable procurement since we got back into the procurement business.

Back in 2001 and 2002 we had just less than 1 percent of our energy requirements coming from renewables. We expect this year to have 6.5 percent. So we feel like we've made a lot of progress there.

We've also gone from 5.25 to about 6.5 just in one year. That's a 20 percent increase in energy deliveries.

So we find that the process is working; it is complex. It is, in some respects, cumbersome, but I think that we're making a lot of progress and we're moving along, and we're getting the goals achieved.

We fully expect that we will be at 20 percent in 2010. And we have projects under contract that are at 13 percent right now for the year 2010.

We put a letter on the table back here. It was from our Senior Vice President; it was dated May 31st to Commissioner Geesman. And it talks about specifically the progress we've made over the years. And it talks about the two items that we think very important to get us to our goal.

And one is the transmission; ditto from whatever -- everything that's been said so far. And also the SEP certainty where something with an escrow account structure would be really very helpful.

We have new resources coming online this year 2006. We had a 50 megawatt wind project come online early this year. We also have in our service area, we're going to have a small hydroelectric project by the end of the year, and a landfill gas project by the end.

We're taking the steps to get the transmission developed so that we can have additional resources. We're underway with our 2005 solicitation. So we've go some projects that we should be bringing to the Commission for approval very shortly.

We issued an all-source short-term RFO for 2007, '8 and '9. It may not get us to the 2010, but we're still looking for renewable resources in those years, as well.

We expect to issue the RPS RFO for 2006 on July 14th. So we'll see how things move there. And also we're expecting, as we go through the long-term resource plan proceeding that we will show a need, and we will be issuing an all-source RFO. So we expect that there will be some renewables there, too.

So, we think that the process is moving along. I don't know if we want to reinvent if there are probably some things that we could improve on it. I mentioned a couple of them, the transmission, the SEPs.

We do think that also this TRCR process, transmission ranking cost report process, we think that that could be improved and that would help move things along.

We think that going beyond the 20 percent is something that we want to do. We think that there's some things that need to be done there. Some studies, perhaps in how would, say, going to 33 percent affect the transmission and the distribution system. We don't know how, having all sorts of PV on rooftops, will it affect the distribution system. So we think that there's probably some need for review there.

And we feel that incentives probably work better than penalties. So, as we move beyond 2010 we'd like to see some movement toward incentives for additional renewable procurement.

ASSOCIATE MEMBER GEESMAN: Now, Terry, the Matson decision, we mentioned before, very clearly reminds each of the IOUs of provisions that have been in the Public Utilities Code for some period of time, about a preferred return on investment for investment in renewable projects.

That would seem to me to be in the incentive category, as opposed to penalties. But it has yet to elicit any interest or activity from the utility sector. Is your company actively considering an investment directly in a renewable project?

MS. FARRELLY: Yes, we are actively considering ownership in a renewable project for, I believe it was 2005, and I can't remember if it was 2004, as well, but we requested bids for utility ownership and options and that sort of thing.

So we haven't, as a result of those RFOs, we haven't come up with something that we can bring for approval. But that is something that we're very interested in doing, and we're spending a lot of time on that.

ASSOCIATE MEMBER GEESMAN: Thank you.

COMMISSIONER BOHN: Can I just interrupt for one second. One of the things that comes up, and I'd really like to address across all three of you, that report said that one should anticipate 20 to 30 percent contract failure rate. And then it talks about permitting and siting and all the stuff that sounds a lot like it's in control of the government or some form of the government that tends to get in the way of getting this stuff done.

I guess my question is, or my observation and my question, it seems like one alternative is to sort of over-commit on the basis you're going to have 30 percent failure rate. The other seems to me a more sensible approach is to reduce that rate to somewhere close to zero.

That means that you all have to evaluate the likelihood of whatever contracting party you engage with is going to deliver it. That doesn't strike me as a very complicated process. It shouldn't permit, it seems to me, a 20 percent error in that. I mean you got whole staffs of people who do this stuff.

How credible is that 20 to 30 percent failure rate?

MR. WAN: I actually don't know the source of that information. I can say that this topic actually ties back to the discussion we had last week on credit.

And when we have some teeth in performance standards and some teeth in penalties, and ask people to post credit when they don't perform, that's how you avoid failures.

So, the question I have for people who did the study is did they dig deep enough into each of these contracts or the entities to see what their performance standards were.

Even the best performance standards, John, will have some failures because things happen in a permitting process, in the financing process, or some of our suppliers have had a difficult time to get turbines at the right price.

We, I think you have seen that all three utilities have voluntarily over-procured anyway. the original requirement or goal was 1 percent per year. But we quickly realized that was not going to add up to 20 percent by 2010. So we're on the path of over-procurement anyway.

COMMISSIONER BOHN: I'm okay with the fact that there will be inherently some failures just because stuff happens. But it would seem to me that a 20 percent failure rate, or a 30 percent failure rate, it's hard, I guess -- it's hard for me to understand that the process of evaluation that leads to contract signing would not look into all of the normal causes for failure, and that those, indeed, would be part of the criteria for signing a contract with firm A as opposed to firm B.

Presumably there's some, I don't want to say checklist, but there's some judgmental process that goes on, does this person have a site under contract. Does this person have the financial wherewithal. Has this company done it before. I mean all the normal sort of investment decisions.

And if you do that it's hard for me to see that you're going to get a 20 or 30 percent failure rate. What you might get is a bias toward established players. And then I guess the decision is how important is it to encourage unestablished players.

But there should be some kind of an evaluation process that's pretty clearly articulated.

MR. PIZARRO: Let me -- I fully agree and I think there are at least three stages in the way we think about this. The first is that project viability check. It's due diligence. And we try to perform a pretty rigorous process. We've learned a lot on our prior solicitations and so we do have a checklist. In fact, we've discussed elements of that checklist with the market as a whole through our workshop and with the energy division and our PRG.

So we do go through it and take a look at what's the -- who is behind that contract and what steps have they taken already. Some of the steps you enumerated.

The second element is contract formation. And insuring that a contract is both robust and balanced, but also tailored to a particular project development and developer. And without trying to create an excuse for our long period of time that our solicitations have taken, particularly the first, it's gotten better, but it's still taking a little longer than any of us would like.

Part of that is the dialogue and negotiation between us and our counter-parties in arriving at a set of contract terms that gives us, as Fong said, enough teeth in terms of the performance management. But it's also workable for that developer.

And then the third stage is the whole contract administration and monitoring process. It's tied to the contract because you need to form a contract that creates milestones, so especially if you're looking at a development that is a newer technology, or has more technology risk to it, we've looked for ways to tie that risk further to the development process and the developer in a balance way. But identify clear milestones early in the process so that if we do have a failure we know it earlier rather than later, and can adjust our procurement appropriately.

The whole flip side of this and a concern I have when the aggregate figure of 20 to 30 percent comes up is this. I think, as Ric earlier mentioned, there is a broad range in their studies. Again, like Fong, I haven't seen the details but it sounds like with some counterpart or with some load-serving entities there may be a very low or zero failure rate; with others it may be a higher one. I would expect there's some correlation to the kind of steps I just talked about.

The other component to this is that although we are all very committed to increasing the percentage of renewables, we do also have to acknowledge that there is a reason that in today's environment not all of our renewable procurement is happening through the RPS program.

We've been fortunate at SCE that we have not had to access SEP funds in prior solicitations. But we expect we will shortly. And likely with some of the '05 contracts that we're completing here.

So, as part of the whole least-cost/best-fit math, these do tend to be more expensive in economic terms. They do bring other benefits. We need to be careful that we don't create a -- translate that 20 percent requirement to something higher. Because we need to be mindful of the overall economic impact on our customers' portfolio.

So we'd rather see the strong management to the steps I described to get to the right place. And to the extent that we see more renewables that are economic, we see the renewables that can compete in our all source solicitations are providing an overall value under least-cost/best-fit, we'd be thrilled to sign even more, further than 20 percent.

But, what we're trying to do is make sure that to the extent that these do impose a higher cost overall today, we're meeting the 20 percent target without necessarily imposing extra costs on our customer portfolios.

ASSOCIATE MEMBER GEESMAN: But doesn't the MPR SEP mechanism protect you from that problem?

MR. PIZARRO: It does, I mean it does provide a lot of help, John. But, again, if you take it to the extreme, although it's protecting our bundled customers directly, they still pay a share of the public goods charge that's leading to SEP.

So I think there's a societal cost there. And we just need to be mindful of that. There are limited SEP funds, and I'd rather see them be employed in a way that optimizes the value for all of society.

MR. WAN: John, I want to come back to two criteria you gave earlier that we do look at in our all-source solicitation very clearly. One is viability, the viability of technology, the viability that the project, itself, based on the site, and the track record of the developer. Those two are among the criteria that we look at.

In terms of renewables it's a little more challenging. For wind it's easier to see if

they have records in terms of met towers,
measuring whether there's any wind.

And I can point to geothermal. Unless someone has drilled enough test holes they can't really tell. And some of those holes go down pretty deep and can require up to $5 or $10 million.

And in terms of solar, the Stirling project is one where you can see it clearly needs some advancement in technology. So there's not a certainty on whether they can deliver the 500 or 1000 megawatts.

So some technologies are easier to see than others.

MS. FARRELLY: And I'd like to say I'm in my third year of this renewable procurements, and in that time period we've had one contract that has failed. So I'd be interested to see how we've developed the 30 percent.

Additionally, we look at the same -- we have the same milestones in our contracts in terms of what backing does the developer have; what is the technology. But we haven't gotten to the point where we're drilling down to a zero failure rate, because we think that there are some emerging technologies, there are some emerging investors and that sort of thing.

So, what we want to do is have sort of the portfolio of resources where we have proven technologies and things that need a little bit more work. And the same thing for the developers, as well.

ASSOCIATE MEMBER GEESMAN: Commissioner Pfannenstiel and Brian Prusnek from the Governor's Office are joining us.

And I think we're ready for our next speaker.

MS. DOUGHMAN: Okay. Our next speaker is Mohammed Beshir, Los Angeles Department of Water and Power.

MR. BESHIR: Good afternoon. Thank you, Commissioners, for extending the invitation to LADWP to participate in this discussion. At LADWP we do think our RPS programs are very important, and LADWP is very committed in meeting RPS goals, which is set by our governing body, which is the City Council through our Board of Commissioners.

At LADWP we do have 20 percent by 2010 goal, which is exactly the same as the IOUs today. We originally had 20 percent by 2017, which was, of course, accelerated up to 20 percent by 2010 recently.

So, I guess there was discussions about being the same or different, what-have-you. I guess there are considerations what we mean by those things.

LADWP goals and RPS, we did have similar kind goals prior to the RPS. We did originally were talking about 50 percent of our load growth being met by DSM, DG and renewable portfolio. And that was started in August of 2000. So this predates the RPS program.

We have -- renewables we describe similar to the state. We have minor variation on the hydro plants, but that was done to accommodate our output at hydro plants, which we have a few over 30 megawatts. But that is consistent, everything else consistent with the state definitions.

We have had the RPS programs since 2004. At that point our renewables portfolio standard was 4 percent. Today we are happy to say it's 6 percent and going up. So we are meeting -- exceeding the 1 percent per year goal.

Our RFP renewable RFPs, we have had a

few. One in 2001. And through that RFP process we did acquire two major renewables. One was ownership, which we are currently developing. A 120 megawatt wind project. We had signed on a PPA for a 40 megawatt biomass project, which is in the early development. And I guess with PPAs there's a lot of uncertainty still on that project, as well.

And as part of our due diligence we did, the same thing we had a geothermal which never materialized.

And as our RFP we had, we issued, was in June 2004. Our goal at that time was the 20 percent by 2017. So the goal of that RFP was to meet 13 percent of our RPS by 2010.

With that RFP we were very successful. We had over 37 projects -- 57 projects, actually was proposed. Nine was selected for further consideration and negotiation. We have entered in two contracts which are in operation today. One is in the approval process; four are in various stages of negotiation and project development; two have opted out and terminated.

As part of our process also we are engaged with the SCPPA, Southern California Public

Power Authority. That's a joint authority which we do some procurements of our resources. Through that we had issued an RFP in 2005.

We have eight projects we are considering and negotiating with. And I guess it was mentioned earlier, we had one project which was signed recently, a wind project. Six are in various stages of negotiation and project development. And again, one has opted out from the project; that was a geothermal project.

So, some of our experience with RFPs. Typically in the RFPs we have sent out we had requirements for project size. We looked at project, we had identified what kind of project types, is it baseload or dispatchable or all kind of resources.

We always have been identified ownership in a preferred procurement mechanism for us. We have also provided options for all types of projects. It could be property, as well as developed projects, or a different level of project development. Power purchase agreements of different terms, five, ten, 15, 20 years. So it's not really specific, it's not short-term or long-term, but we do have options for developers and provide us to choose.

We have so far for most part we have asked for bundled energy and REC. We haven't asked for a REC only, or projects. We always have identified delivery points; mainly would have preferred delivery points within our transmission systems.

We have also had business policies we identified. Could be minority business enterprise issues, or recycling and many other union-related issues. So those are our business policies we also identify in our projects. We provide pro forma agreements, as well as we do require project detailed data.

The difficulties we have had with some of the RFPs was a proposal security. I think there's been a lot to be said for that. We did require having proposal securities for people to show seriousness of their project. But it's a two-edged sword. That gives you the screening mechanism to make sure you have viable and good projects in the pipeline, but also it does discourage some developers, as well as maybe there could be some viable, but with some maybe some push and pull that may make the project. So that, I guess, is a two-edged sword in that sense.

We do like ownership projects, but also discourages some developers and providers, because they may have some tax appetite or they do see a lot more upside on owning the project, or flipping or selling that project down the road. So that sometimes is also a consideration.

Business policies we have. In most cases, people don't -- developers do not like the different business policies we have. But those are policies we cannot get out of, so eventually that was -- takes care of the negotiation.

So we have some contractual government contracting provisions, confidentiality, indemnification issue, audit provisions which are sometimes difficulty, cause difficulties to developers and providers. But normally we do, we are able to negotiate on those.

So, in general, those are some of our experience.

Some of the things we are doing. We are, I guess we do -- renewables, and we are very serious about developing renewables. So the way we go about developing renewables, we do look at the whole aspect; the energy considerations, the transmission issues; the integration issues within the system. And how do we better look at that from a long-term plan perspective.

So, overall, I think, as was said by Ric and I think was testified in some of the reports CEC has developed or produced recently, I mean we have had some successes. In fact, in view of some of the difficulties or some other people feel. We are successful; we are very focused on what we are trying to do. We have major projects on the pipeline hoping in the very near future they will materialize.

So we are looking at first streamlining the process farther, which includes coming out with pro forma agreements. We are planning to issue new RFP shortly to supplement to what we have in the pipeline. We have major transmission upgrades we are looking at. I guess we'll be talking about the green path project, which is essentially looking -- we have very focused approach to go where the renewables is. And we are working towards that with major transmission upgrades.

And the same thing is also happening in Tehachapi, where we are upgrading our transmission system. Today we are building a ten-mile line to spur from our transmission line to where the renewables are. That is in association with our Pine Tree project. And we do see that is a focus for expanding that renewable wind from the Tehachapi. So we do have other projects in the pipeline along with that.

We are also looking at getting to some wind and maybe geothermal up in the Utah/Nevada area with an upgrade of our STS dc line from 1920 to 2400 megawatts. That's in the pipeline. We are working through WECC to get an upgrade on that. And that is going to bring major renewables to southern California.

So, in addition to that, of course, we are separate, but I think the beauty of that is we do look more in an integrated fashion. We provide a lot of value to the developers. I think that has been proven.

One challenge we have today is, of course, how do we pay for the major transmission upgrades we are looking in our system, as well as for some of the major renewables we are procuring and planning to procure.

Today we are in the budgeting process,

as well as going through the different neighborhood councils. Our City focus, try to see how to get the additional revenue to make that happen. And we are very positive of the reactions we're getting from our customers. They are supporting our effort. And hopefully will get the necessary funding to be able to complete the projects.

ASSOCIATE MEMBER GEESMAN: You know, I mentioned my admiration for the clarity of commitment in the CPUC's Matson decision. But I think the real model for that no nonsense, no equivocation, the goal is the goal is Mayor Villaraigosa. And I know that at his direction the performance evaluation criteria for your general manager have been amended to include progress in meeting your 2010 renewables goal.

And to my friends in the investor-owned utility sector, searching for a common standard, I would suggest you recommend that to your utility CEOs as a way to focus your commitment.

MR. BESHIR: Thank you.

MS. DOUGHMAN: Okay, should we move on to the next speaker, then? The next speaker is Valerie Beck from the CPUC.

MS. BECK: I've been asked to be brief, so I will comply. First of all, I'd like to say I've had the luxury of listening to all the other speakers and being the last speaker, and I very much appreciate and understand some of the observations that have been made today. Particularly regarding the complexity of the statute, which is sometimes prescriptive, as well.

We've heard from the utilities about the progress that has been made to date. We've also heard about some of the obstacles, so I think probably the best thing I can do is just tell you what's on our plate for this year at the Commission.

In February we opened a new rulemaking. And in that rulemaking we plan to address issues that have come up today regarding participation of ESPs and CCAs and the small utilities and the RPS program.

We have also opened up a rulemaking to implement the California Solar Initiative. And one piece of that will deal with how those projects may or may not be eligible for the RPS program. We also plan to address RECs this year.

And most recently in May we approved the

IOUs' 2006 short-term procurement plans. The utilities are getting ready to issue solicitations in July or by July, this month.

Just the last Commission meeting the Commission approved a decision regarding application of backstop cost recovery for transmission costs that are not included in transmission rates.

We have also acted upon a recommendation by the Tehachapi working group to designate a specific RPS transmission project manager. We just did that a couple of weeks ago. Most of you know him; it's Tom Flynn. He couldn't be here today, but he has actively started his new role.

In terms of other decisions coming down the pipe, we plan to talk about -- issue a decision about transmission, streamlining transmission permitting; resolving some of the ISO queuing issues. We plan to issue a new MPR in the next 60 days.

That's it, thank you.

ASSOCIATE MEMBER GEESMAN: Thank you, Valerie. Why don't we go to the panel.

MS. DOUGHMAN: Jam Hamrin will be moderating the panel for us.

MS. HAMRIN: I don't know how much moderating I'll do unless you start to look like you're getting in fist-fights. But I do want to remind you all that we have limited time, so please highlight the issues that are really the most important.

Remember, the transmission discussion is next so you don't need to use this time for transmission. You'll have plenty of time in the next section.

You also can provide more information in your written comments, so your comments here are not the last we will hear. You certainly should feel free to expand on those in your written ones.

And don't spend a lot of time on an issue that you've already briefed before the PUC. I don't think we need to redo briefs and reply briefs.

And please speak into the microphone. So, John, have you found a chair down there, too? Who would like to start off? Steven, you're next to the microphone.

MR. KELLY: Thank you, Jan. Steven Kelly with Independent Energy Producers. And, Commissioners, I appreciate this opportunity to talk about the RPS. You asked for candor and I think I can do candor.

(Laughter.)

MR. KELLY: After hearing the presentations I just got a warm glow about how the RPS is progressing here, so, it's very exciting. But what I'd like to do is talk briefly, start my presentation with a little metaphor, and then raise some issues about how California's proceeding with its RPS.

And the metaphor is I harken back to the workshop we had last week. And this is how I think of how the RPS is being implemented in California, and the reasons why it sits wherever it sits.

Last week there was a workshop here at the Energy Commission on credit collateral issue, a very important issue. There were a number of panels. I think one had 11 people; the other panel had 13. There were five microphones. The utilities controlled two of those microphones.

So you'll see when you go back and look at the record a lot of speaking done by the utilities, and very little done by everybody else. And I don't think it was because other people didn't have something to say, but there's a structural impediment about their ability to do that. So it's kind of a metaphor for what's going on in the RPS in California today.

Let me go on and talk about -- I've got one, I was glad Jan grabbed this one. It's all about infrastructure.

(Laughter.)

MR. KELLY: But let me talk briefly about this issue of progress, because it sounds like everything is moving forward swimmingly. And I want to flip that a little bit because I want to describe what I see in terms of the success of the California RPS to date.

There's lots of contracts that have been entered into. And there seems to be a tremendous -- some issues about the viability of those contracts coming online, or else we probably wouldn't be having these series of workshops today.

I'd note that in the presentation there's something like 241 megawatts that have actually come online since the California RPS was implemented by the Legislature. That's about half of what had come online the previous three or four years when we didn't have an RPS.

And the Energy Commission has reported that as a percentage of retail sales it appears that the RPS is actually moving backwards because the percentage is dropping from the utilities, anyway.

When I see those kinds of numbers I question where we really are in this process. And I wonder what is going on in implementation and why we're here.

I look at things like least-cost/best-fit methodology for determining who's going to be awarded contracts. And I think that's actually a good methodology, or should be, in theory. But then learn that there's tremendous problems about contracts that are awarded that have lack of site control, or lack of transmission, a lot of discussion of that.

And I don't understand how they can move through the evaluation process and not have issues like viability, site control and transmission addressed.

I notice that there's no SEP monies that have been awarded or needed yet. Apparently there's two contracts that may be coming forward over the last three years. So no contracts from renewable developers have been selected that would actually trigger that mechanism. And that's fine, that's great, because I actually think renewables are relatively cheap.

But I'm wondering, based on a record that shows that there's a probability of a number of the awarded contracts not coming to fruition, who didn't get selected that might have gone forward in a more timely fashion had they had SEP money.

I'm not privy to this kind of information; it's all redacted; it's not very transparent. But are there other developers that bid projects that might have been able to come online, having triggered some of the available SEP money which is available by the Legislature, and is now under a threat of being taken back by them because it's being unused.

So I wonder if there were more contracts or other contracts out there that could have been entered into, in addition to the ones the utilities already have executed, that might have facilitated a better record of achievement in terms of coming online in a timely manner.

The issue of the independent evaluation has come up, and that is a mechanism that the Commission has imposed. I think it is a mechanism that is necessary, given the way the RPS is being implemented.

I do have concerns about that. The independent evaluator that's been used to date is somebody who's under contract to the utilities; ends up being a expert witness in the advice letter process for the utilities when they move forward with the contracts.

I have some concerns whether there's a conflict of interest there, and if we're actually getting independent evaluation of the RFO process. And look forward to seeing the Commission hopefully dealing with that issue and making sure that the marketplace is comfortable; that the RFO procedures are actually being independently -- or being administered in a level playing field kind of perspective.

And I just want to final my comments with one observation, and this is an observation that I've made to the Commission here a number of times in the past.

It's not clear to me that we're ever

going to be able to see progress in the RPS the way that stakeholders like myself expect it to be if we continue to have a market structure in which the utilities, particularly, as the selectors of these contracts, have a business interest in developing their own projects or building the transmission where they want.

It's a fundamental issue that goes to the hybrid market structure. We've had debates about this for a long time. But I still am not convinced that that structure is going to work and insure that we get timely and effective development of new generation, new infrastructure when that's in place, because I just think the motives and the incentives are skewed under that structure.

So I leave it at that.

MS. HAMRIN: Okay. Next.

MR. MORRIS: Hi, I'm Greg Morris of the Green Power Institute. I didn't really come here with a set presentation to give. But I have to say that I am somewhat interested in several utilities saying let's stay the course when as far as I can tell the course we're on will not get any of the utilities to 20 percent renewables by 2010.

In fact, I remember a year or two ago SCE, the one utility that's actually close to 20 percent, announcing that they had already achieved 20 percent. However, they went from a little over 18 percent in '04 to a little under 18 percent in '05.

So I'm wondering how staying the course is going to get any utility in this state to 20 percent by 2010. Certainly as I look at the projects that are already in the pipeline, and that does not include very many from 2005, since they haven't been -- from the 2005 solicitation since they haven't been announced yet.

But what I see in the pipeline that has been announced with signed contracts certainly won't get us close to 20 percent by 2010.

And I am one who is bringing up this issue of contract failure rate even before that study came out. I know that there was a substantial contract failure rate back in the '80s when we had the standard offer 4 contracts, which were, I think, unquestionably the most attractive contracts that anybody's ever had to work with.

Contract failures happen for a number of reasons, but I think that when we had a process that is really trying to push every renewable developer to the lowest possible cost that they can live with, we're pushing them below the cost that they can truly live with.

I know a lot about biomass, for example. I know that there have been several biomass projects signed up at rates that simply cannot support a biomass plant. And I know that some of those have already been withdrawn. And then others are likely to fail, as well, because there simply isn't any reasonable way that those projects can be viable.

So, I think we do have some fairly serious problems here. I look back to the standard offer 4 process where we had a very significant success with the building of renewables. In fact, the 10 to 12 percent renewables we have in the state right now are mostly a result of that process.

And I wonder whether we wouldn't be better off with a standard offer type of process where developers could start from the basis of knowing what they can work towards, and can plan their projects accordingly.

Right now we have a process where people are bidding plants into RFPs. And then even if their bids are accepted on a short list, they are then negotiating with the utilities, trying to push them down. And probably, I would imagine, the developer is trying to push them up.

And I'm not sure that that really leads to viable projects. I think we have to think about that. And certainly the SEP mechanism, as we've already discussed, is not very conducive to financing projects.

So, --

ASSOCIATE MEMBER GEESMAN: Do you perceive an avenue in the current system for bilateral contracts?

MR. MORRIS: Well, there are several bilateral contracts that have been negotiated; although as far as I know they've been mostly or maybe exclusively with existing, but idle, renewables.

ASSOCIATE MEMBER GEESMAN: If a developer had a bilateral contract that it was willing to sign at the MPR, couldn't that go forward outside of solicitation? Do you think the utilities would resist that?

MR. MORRIS: I wouldn't know that. I

couldn't answer that.

ASSOCIATE MEMBER GEESMAN: Well, you're an observer of the market, though, and --

MR. MORRIS: If the MPR -- well, I think the MPR is certainly a reasonable price level to allow a lot of renewables to go forward, but not necessarily, for example, a biomass project.

MR. WAN: John, we've signed some bad bilaterals.

ASSOCIATE MEMBER GEESMAN: Yeah, it just strikes me, because we touched on this standard offer ground a bit last year in our IEPR hearings. And there are those that are enthusiastic about that approach.

It would seem to me that somewhat short of imposing that level of standardization, the status quo environment allows a renewable developer willing to sign a contract at the MPR to sure bring an awful lot of leverage onto the utility.

If you read this Matson decision which says if these guys don't make their goal, there are going to be serious consequences. Well, it would seem to me that that would provide a developer with at least some ammunition if he's willing to sign a contract at the MPR.

MR. MORRIS: Um-hum. Well, I think that would be a great idea. I just -- I don't know what motivates the developers to go to the utilities to try and make that process work.

ASSOCIATE MEMBER GEESMAN: Commerce.

MR. MORRIS: Indeed. And finally, just an observation on the fact that we have accelerated rather drastically the 20 percent from 2017 to 2010. That's good, but only, in my view, if we follow that up with the 33 percent by 2020 target that the Governor had set.

Because otherwise we risk doing exactly what we did in the '80s, which was we had this boom and bust with development of renewable projects, because they all were done in one five-to-six-year segment; and then there was no more development. And I think that would be a very unfortunate outcome.

If we're going to push hard for development now we need to follow that up with a continuing development so that we sustain the renewable industry, not only the operations of facilities that get built, but the development of new renewables over a longer period of time, or we're not going to attract the developers to the state.

So, thank you.

COMMISSIONER BOHN: May I ask a question. I know nothing about biomass, so I can speak with complete authority.

Is it your position that regardless of the cost, whether it's economically viable or not, one should proceed with biomass? I'm having trouble finding out how far you want to take that argument.

MR. MORRIS: Biomass is a very interesting renewable technology. It is, in simply looking at the production costs of electricity -- and I'm talking about solid fuel biomass, not biogas here -- it is probably the most expensive of the renewables.

However, it's also the only renewable that provides a whole host of nonmarket benefits in the area of waste disposal. It avoids landfilling of waste; it avoids open burning of agricultural and forestry residues; and it promotes forest management improvements which reduce wildfire risk, improved watershed productivity.

In fact, since we started the whole restructuring process back in the mid '90s, we've been, as a state policy, still codified in the Public Utilities Code, trying to push some of those nonmarket benefits into being compensated outside of electric ratepayers. And have had no success at all in doing that.

COMMISSIONER BOHN: So your argument, as I understand it, is it's not economically viable, but there are other reasons that we should subsidize or somehow help out biomass.

I guess my view is that's probably outside the purview of the discussion that we're talking about. In other words, if it's not economically viable under the terms and conditions of the RPS, it seems to me that's a decision, maybe regrettable, but it is not a decision that the market should deal with.

MR. MORRIS: Well, the Governor did, indeed, issue an executive order just a couple months ago, I believe it was, that would ask the PUC to open a proceeding to, in effect, establish a biomass segment within the RPS.

I don't know where that's going to go. I don't know that the Governor's Office has followed that up with any actual policy recommendation.

But yeah, biomass is a tough one because it gives these very significant, and in fact our studies have shown that the nonmarket benefits of biomass are worth considerably more than the electricity they produce.

So, how do you achieve that goal. We haven't figured it out yet, that's for sure.

MS. HAMRIN: Thank you, Greg.

MR. MORRIS: Thanks.

MS. HAMRIN: Who would like to go next. Diane?

MR. WHITE: I'm John White with the Center for Energy Efficiency and Renewable Technologies. Our group includes individuals who are part of companies who are seeking to bid.

We also have organizations that are participants in the procurement review group. And then we have those of us like myself that are interested, and not always bemused, observer. So I guess I'll just speak for myself today, and not speak for everybody, since some of the folks bidding might have a different view than those doing the reviewing.

I think the central problem with the California RPS is what we've called the words-to-megawatt ratio problem. And if you add up all of the television ads that the utilities run, all the press releases, all of the filings and all of the statements of good intentions by everyone from the Governor on down, if we acted about renewables as much as we talked about them, I think we wouldn't have lost our leadership role in the country that I think we have lost.

On the other hand, I think we have learned a lot in the course of events. We are also very involved with the City of Los Angeles and make a great deal of effort there. We do believe that the incentives created for the General Manager by the Mayor have had a tangible effect on that institution.

And we also think that the PUC has yet to demonstrate the capacity to stick with its guns on the question of the IOU compliance. I don't think anyone yet believes that the Matson decision necessarily means what it says until we actually see either the progress get made, or the penalties get inflicted.

On the gas side there's no incentive not to build gas it would seem, because of the automatic pass-through of the rate increases. And I think one of the things that's changed since the RPS was adopted is the different view we now should have about our vulnerability on natural gas.

While we have been implementing the RPS over the last several years, we have steadily increased our consumption of out-of-state coal. We have begun to become a magnet for people who want to convert gas in Australia and Indonesia and carry it across the ocean for purposes of making electricity and heating hot water in California. And it seems to me that's a much harder and financially more risky proposition than to develop the renewable resources that we have within the state.

We've worked hard on the Tehachapi issue. We support it. Southern California Edison's trunkline decision, it wasn't perfect, but it was a good start. We're glad the ISO has picked up on it and is following through. We're disappointed that PG&E's not been as cooperative on Tehachapi. We're glad the ISO's got everybody moving forward.

We hope that the interagency politics can become manageable so that we can make decisions in a timely fashion. That is part of California's words-to-megawatt ratio problem is the timeliness with which decisions get made, whether it's permitting or whether it's transmission.

The other thing with the RPS that I think we've come to find out is that the annual solicitation that just sort of keep going out for solicitation; without seeing those decisions connected to transmission decisions is a problem. And that ultimately what we're going to have to do is really have work plans for each utility that would provide a mechanism for coordinated investment in transmission and procurement. Those two need to be together.

Some of the problem comes from the FERC rules about people, different sides of the company can't talk to each other and stuff like that. But this is where I think the government agencies need to step back from this mechanistic process of the annual solicitation. And look at maybe working back from the 2010 goal, and say how are we going to get there. What are the combinations of projects.

Commissioner Bohn's question about can't we do better than avoid a 20, 30 percent failure rate. I think the answer is we should be able to. But not the way we have organized ourselves.

I know that there are members of our organization that are members of the procurement review group. We are not convinced that that process is transparent enough or robust enough. And we would much prefer to have the PUC, itself, and its staff be in the middle of those transactions, rather than have it walled off from public agency representatives the way it is now.

I can just tell you that some of the projects that have emerged from that process strike us a curious. I don't want to say which ones they are, but let's just say that there's some folks that got picked that wouldn't have been allowed to give money to our group, given what we knew about their business practices. So there's something that's kind of weird about some of the contracts.

So I think that the other problem, I think, is that the situation has really been biased against the sellers in a couple of ways.

We have a very curious policy with regard to renewable energy credits in terms of the RPS compared to almost every other state and country in the world. Where we basically do not allow, under the law, or at least some people's interpretation of the law, you to separate the attribute from the delivered energy.

I don't think we're ready for interstate REC trading as it's been called. But I don't see fundamentally what the difference is between a Geysers transaction between Southern California Edison and PG&E, where the energy stays in northern California and the renewable credit goes to Edison, from a separation of a REC for an ESP.

So it seems to me that giving sellers more choices, including letting them sell some short-term contracts, is the only way we're really going to ever get the ESPs in the game. And while we've been having this lengthy conversation, the ESPs haven't been complying with the RPS.

And I don't think that's just because some of them don't want to, I think it's because we've not made it possible to give them choices.

So I think the Legislature needs to act in some fashion. We proposed a mechanism called, we call walk before you run, where you allow a very limited kind of transaction where you have the energy delivered to the state, to the ISO, or produced in the state from an eligible new renewable. And then allow there to be a separate transaction for the attribute.

Seems to me that we used to do that kind of tracking back in the day when we had retail claims. I think Ms. Manrin and her organization had an ability to do that. The Energy Commission had the ability to track claims. I don't know what's so fundamentally different about a limited REC transaction where you basically have people prove that they bought what they say the bought and didn't sell it twice.

I think there's no reason for us not to allow that. I think it would make a lot of difference where the transmission constraints exist.

And then I also think that the money that the Legislature put forth in the budget for the PUC Staff that the Governor approved, will allow for the PUC to take control of the RPS process and not let it be outsourced to the utilities and the PRGs quite so much. I think that will help.

I think the Energy Commission recommendations in the IEPR with regard to transparency of the RPS are important. And I'll leave the transmission discussion to the rest of the panel.

MS. HAMRIN: Thank you, John. Okay, we'll go then to Nancy Rader.

MS. RADER: Okay, thanks. Nancy Rader with the California Wind Energy Association. I agree with a lot of what I just heard. In preparing for today and really stepping back to look at the big picture, I came up with these thoughts.

First of all, you know, I was involved in the negotiation of SB-1078, and I admit it's an ugly law. It's complicated. But there's a reason it's the way it is, and that has to do with politics and compromise. And I really would not want to revisit that process again.

I think the basic framework of the RPS is one that we still support. It promotes the objective evaluation of intermittent resources which is very important to us. We think it does promote least-cost procurement in general.

Although we agree that we find some of the contracts surprising.

We think the law has led to greater utility acceptance of wind, which is a low-cost resource. And we think that has been a good outcome.

Despite the fact that not a lot of megawatts have come online, though I would point out that the number is bigger than 240 megawatts. I notice that there's two repowers listed in the database that are listed as not online, which are on line. That's 27 megawatts.

There are also 38 megawatts of repowers under construction now, so that number will be over 300 megawatts by the end of the year.

But despite that, there's been a huge amount of progress made. We have a transmission plan into the Tehachapi resource area which is going to open up 4500 megawatts or more. Hopefully that plan is going to be approved at the ISO in a month or two.

There are over 5000 megawatts of wind in the ISO queue. We have started to repower old sites, 45 megawatts have been completed; another 38 megawatts under construction.

And most of all, the wind industry in California is alive. Our members are completely preoccupied in contract negotiations and project development. We are expecting big announcements later this summer. We are anticipating some dramatic news from some of the utilities.

In short, there's a whole lot of stuff in the pipeline. I think that, you know, we're not short of complaints, I think the PUC will attest to that. We have a lot of complaints about the process.

But, a lot of progress has been made. I think there's been learning happening at the utilities, particularly I would say that Edison, I think, has come a long way in understanding the realities of financing, and the understanding the cost to the project of imposing certain requirements. Our members have seen flexibility there at that utility that we're pleased about.

And, in general, I think we have to not be too surprised that we haven't seen more results given. That this is the electricity business, after all. It's a lumpy business. We're basically waiting for transmission to be built. And we'll have a conversation about that later. I think there's a lot can be done there. But, the fact is we have transmission being planned and built.

So, I would agree with the utilities that it would be counterproductive to look at wholesale changes with the RPS at this point. And what we need to do is continue to make incremental improvements.

Thank you.

ASSOCIATE MEMBER GEESMAN: Nancy, assuming that you and the utilities are correct that we're headed in a good direction as regards the 20 percent goal, do you think the existing program structure is a good foundation to build from to accomplish the 33 percent goal that both Commissions and the Governor have put forward?

MS. RADER: I do think the framework works. We have, from the very first day, called for much greater standardization of contract terms. I think that would help greatly, both in terms of increasing participation and lowering bid prices.

And it would reduce the negotiation time. I mean it's taking way too long and way too many resources for people to negotiate contracts.

So I think that's, you know, next to transmission, our number one issue.

We'd also like to see standardization for projects that want to repower that shouldn't have to go through that bidding process. I think that's why we're not seeing more repowers.

I think, you know, it would be nice to have greater uniformity and transparency on the least-cost/best-fit process. We think it would help a lot if utilities provided some very detailed examples about how the least-cost/best-fit process works so we can have a better understanding and there can be a little less secrecy.

ASSOCIATE MEMBER GEESMAN: Do you read the Matson decision as requiring that in the next round of contract submittals?

MS. RADER: Transparency in least-cost/best-fit?

ASSOCIATE MEMBER GEESMAN: Yes. And in the valuative criteria that the utilities apply?

MS. RADER: I guess that's not ringing a bell. We would like to see an example to show us exactly how a bid would be put through the least-cost/best-fit process so that we can understand what capacity values are being applied and things like that.

We don't really have a basis for complaint right now, given that we got a lot of wind megawatts contracted for and signed. So we're not smelling a problem or a bias, at least towards our resources. But it would, I think, help to understand better how the process works. I'm not sure about the decision on that point.

MR. WAN: John, can I just respond to her?

ASSOCIATE MEMBER GEESMAN: Yeah.

MR. WAN: We would be glad to share our evaluation process with any nonmarket participants who would sign a confidentiality agreement.

MS. RADER: Do I count?

ASSOCIATE MEMBER GEESMAN: Yeah, I --

MR. WAN: I don't know if you count. I don't know if you count.

(Parties speaking simultaneously.)

ASSOCIATE MEMBER GEESMAN: -- I have to tell you, Fong, --

MR. WAN: You have to ask yourself.

ASSOCIATE MEMBER GEESMAN: -- that doesn't quite get there. There's probably no bigger critic of our current approach to transparency in the room than me.

But I read the Matson decision; I read what I regard as a disappointing decision on confidentiality by the PUC, but with some enormous carve-outs in the renewable area, as creating some openings here that perhaps aren't commonly understood.

I think there's going to be a lot more brought into the sunlight in terms of how the valuative criteria are formulated and applied. And what information in the renewable procurement area really should rightfully be in the public domain.

And I'm sure we'll have ample opportunity to fight about that in the future. But I think Nancy makes a pretty important point in terms of instilling any confidence in how the program is being conducted.

MS. HAMRIN: Dan Adler.

MR. ADLER: Thank you. I'm Dan Adler with the California Clean Energy Fund. I'm going to be brief, practical and optimistic. And I think because I no longer work in state government, I can be all three of those things.

(Laughter.)

MR. ADLER: In my current role -- I left the PUC about a year ago, having worked on the RPS -- I'm traveling a lot more, meeting with a lot more clean energy developers and entrepreneurs.

I hear their feedback on the RPS. And actually it's almost uniformly negative. They hear at the high levels that it's not working, nothing's getting built.

I spend a little time with them and I talk through the numbers that we've heard today and that are now available in the public domain, 50 contracts signed; 3000-plus megawatts; 240 megawatts actually running now. And people start to say, well, that's actually pretty impressive after three years. Maybe I will reconsider my decision not even to bid into the California RPS.

And I think that's important because going on all throughout the west and throughout the United States, throughout the world, is a green rush. Everybody wants renewable energy development.

We need to be very careful that we're not sending, through the natural process of self analysis and navel gazing, bad signals to developers who are not as intimately familiar with these details.

I think one definition of insanity is the ability to keep two fundamentally opposite ideas in your mind at the same time and think they're both true. Another definition of insanity is to keep doing the same thing over and over again and expect a different result. That may be an RPS developer's version of insanity.

But it is possible for us to sit here and say we have a successful program, we have a world-leading program, incredibly complicated. The process of a deliberative body's best effort and a lot of interested stakeholders. And it needs some work. That should be kept within the family, I think, a little more than it has been.

When I was with state government we had a very good collaborative relationship with the Energy Commission. We got a great deal done at the staff-to-staff level. I think that needs to be reconstituted as quickly as possible. And I think you'll see a lot more progress as a result.

One practical point. Reading through the materials prepared for this, I note, particularly in the consultant's summary report, that taking maybe the upside total amount of gigawatt hours that are under contract now, it's an additive, say 6.5 percent, from where we were in 2002. This gets us quite close, 18 percent probably, to the 20 percent goal, at least for the IOUs.

The contract failure issue is crucial. And one practical suggestion I would make now, probably not being able to file this, it should be more of a state regulatory agency interest in how that process goes. There should be dedicated staff who are working on contract failure questions, a hotline for developers.

I have much more exposure to developers now than I did as a state employee and I respect what they're trying to do. Delay becomes failure on a knife-edge. It's not that they don't know what they're doing. They have limited resources.

It is important, as Commissioner Bohn noted, that we will shrink the pool of bidders if we make the process so onerous that only the big balance sheet financiers can get in the game. That is a public interest. And I know that the PUC and Energy Commission Staffs are stretched.

To the extent there's any resources that can be allocated to that, I think that would be a boon.

And finally, to my mind it's not a question of the success of the 2010 goal; it's not even really a question of the success of the RPS, itself. It's a question of the long-term viability of sustainable energy in California.

We can focus on the near-term goals, but if we start making decisions about technologies and financing mechanisms that limit our ability in 2011 to really set those stretch goals, starts doing things like integrating the transmission system into the electric grid, pushing for technologies that look like peaking and distributed generation. For example, solar thermal with electric storage. That doesn't fit in the current pricing mechanism that we're deploying.

And if we go barreling forward with technology choices now, we may find in 2010 that we've constrained ourselves in significant ways.

I'm very heartened with what I see happening out of the Public Interest Energy Research group here. There's a real importance of emphasis on the first megawatt for emerging technologies, the things that we're going to need in the outer years of our stretch goals. And so I've been keeping a clear focus on that. Be to the benefit of us when we're sitting here five years from now, as we no doubt will be.

Thank you.

MS. HAMRIN: Thank you, Dan.

ASSOCIATE MEMBER GEESMAN: Dan, you were the primary architect of the rebuttable presumption mechanism for all-source procurement.

MR. ADLER: Um-hum.

ASSOCIATE MEMBER GEESMAN: PG&E's first out of the box, zero for 50.

MR. ADLER: Right.

ASSOCIATE MEMBER GEESMAN: Any second thoughts as to how to make that a more effective procurement mechanism?

MR. ADLER: Well, I don't know if I would have called it a procurement mechanism at the time. It's a rhetorical device. It's important.

I think there was broad support for it as an idea. It needs a lot more meat around it. And what it needs around it particularly are other financing tools that can support the technologies that would really look like the best fit. Right now it's a least-cost game. Fit is out the window, and one of the first PUC decisions basically said that. We don't know how to make these technologies fit, so we're going to go for least-cost at least for now. And we're still in that environment.

Listening to what Fong said about what they went to get, those are the needs to meet their utility customers' load obligations.

If there was a technology support mechanism in place that made, for example, solar thermal with storage more economically viable, and frankly, if there was probably a little more awareness in the renewable community that the rebuttable presumption is the mantra, then I think you could see it work. You could see more renewables bidding and taking advantage of that financial and technological support on the state side.

Probably too soon to tell, but I do think that's the right way to think about it. And I think it can work in parallel to the RPS.

ASSOCIATE MEMBER GEESMAN: Thank you.

CHAIRPERSON PFANNENSTIEL: Dan, you

mentioned trying to work on contract failure by having some dedicated staff to work on that. How do you actually see that working? I guess there's been a lot of discussion about what we know about the contracts, and who knows what, and what information is available. How do you see that working?

MR. ADLER: Well, I think it should be clear from the moment that an RPS contract is approved, that it is a state interest in seeing it succeed, that it's not just the developer out there on his or her own, or the developer interaction with a utility.

But the developer has friends in the CPUC and the Energy Commission and at the ISO that have a material interest in the success of their ability to go through the various steps, to hit their milestones, get their permits, get the various timely financial obligations met.

And can simply pick up the phone and call some of my good friends at these agencies and say, look, we're not going to hit this milestone if we don't get a little bit of regulatory support.

It's a fine line between favoritism, but

I think once they've been folded into the state's procurement process in that way, then we all have a collective interest in making it happen.

And I think there are two ancillary benefits to that, in addition. One, staff will learn on the ground how the program is working much more than in these annual true-ups, or semi-annual true-ups. They can see what a developer's perspective looks like.

And it might even be possible, and this is probably going to be controversial, but to build into that process if certain milestones aren't met, contracts begin to fail, there's a utility buyout option embedded in that contract. So that that contract is basically a public possession and a public good at that point. And it needs to be constructed, because we're counting on it so heavily to hit our near-term targets.

CHAIRPERSON PFANNENSTIEL: Thank you.

MS. HAMRIN: Thank you. Doug.

MR. WICKIZER: Doug Wickizer with the California Department of Forestry and Fire Protection. I was asked to speak to one item in particular, and that was a jurisdictional issue.

And the issue is the fact that for RPS

or utilization of biofuels they need to be produced with a constraint of complying with the Public Resources Code that state, that being a harvesting of timber under the California Forest Practice Act.

That, in general, has an associated cost of about $35,000-plus per timber harvesting plant, on average.

The question is, again, how this would apply to federal lands and tribal lands. The fact is that timber harvesting plans do not apply to nonfederal lands within California. There are other harvesting issues and costs that go along on those lands, but it's not those produced by the state in that instance.

Internally what we've done to address the cost for harvesting of -- the cost of harvesting on private lands or nonfederal, that can include state lands, county lands, city lands, et cetera, is that we've adopted -- the Board of Forestry has adopted some exemption authority to provide for lower impact operations that result from biomass harvesting to not have to go through a full environmental analysis. Part of that is done in the regulation, itself.

It allows harvesting of certain size material within size limits, so that there's not undue impacts to the natural resource. And at the same time it requires other practices, such as water quality protection, air quality protection, those type of standards remain in place that are operational. The main relief that's provided there is for the cost to review and permitting. So there has been progress in that.

Secondarily, under the Forest Service and the other federal land ownerships that's been a supply issue under renewables constantly. And it's been one of the major complaints of the biomass industry in California.

There's some progress being made in that area in that the concept of what is referred to as a stewardship contract. There's progress being made under the Healthy Forest Restoration Act, and funding being provided to the individual forest to put those fuel-hazard-reduction projects out on the ground and to make them active.

And those are low-cost contracts. That material comes at a fairly reduced value to the purchasers. So I'd say there's some progress in the area of being able to get a more reliable supply of biomass from federal lands.

Is that going to happen today? No. I don't think that that's going to be fully implemented within the next five years, probably.

But on the other hand, there's some things that can help that, and that is some continued backing for the Healthy Forest Restoration Act to make sure that the federal land managers get the dollars necessary in their budgets to conduct and prepare the sales, and to meet the standards of contract preparation that they have.

Their constraints come under the national Environmental Policy Act. But the cost is borne more by the public than by the individual investor, as it is on private lands.

I think that covers that. If there isn't, I'd answer some questions. But I would like to make just a couple of observations to go along with those made by Greg on biomass, in general.

The Energy Commission has put a lot of time and effort into biomass. And I want to recognize and thank them very much for that. Because it does have a lot of those co-benefits of fire hazard reduction, of honestly improved water quality, and reduction of open burning and other air quality benefits that go along with that.

But I don't think that it necessarily gets a fair or level playing field in comparison to some of the other renewables. I shouldn't -- maybe that's a bad statement; I'm sure it is, but let's back it up and say that some of the reports that's been put out by the Energy Commission, such as the Governor's bioenergy plan, and reports that it's sponsored along with the biomass collaborative, there's a list of items in there and recommendations on actions that would better level the playing field for biomass, just from an institutional aspect.

Solar, for example. Mr. Fong used an example earlier. I try this one out and see if it flies. Gets quite a bit of additional subsidy and additional indirect governmental support that doesn't get provided to biomass. The same is true for several of the other renewables.

If that subsidy concept were levelized I think you'd see the competitiveness of biomass increase dramatically. Together with that in starting to solve some of the supply issues, you start to see a little better picture.

I think also along with that is the question of the cost. Well, sure, if you've got to haul biomass off the hill to the valley to produce electricity, that costs you a lot of money. If you ship the electron over the transmission line, through distributed generation, that cost is reduced quite a bit.

And the option of selling electricity at different customers, the interconnection, the wheeling, some of those things that are out there that could be addressed either by the Energy Commission or the Public Utilities Commission, I think still have room for work.

I think if you look at the biomass papers that are out there right now, there's some consensus that between 1400 and 1700 megawatts of power with just biomass available of residue today. It can be captured within the next -- by 2010, if the efforts are made and the institutions are revised.

So, I would like to say that I agree with Mr. Adler that there is progress certainly being made. But that there's room for additional progress and incorporating some of the other benefits that come from these renewables.

So, thank you.

MS. HAMRIN: Thank you, Doug. Jeff Lam from Powerex.

MR. LAM: Good afternoon, Commissioners, attendees of the workshop. I know time is scarce, so I will be brief and probably file more detailed comments in our written submission.

My name is Jeff Lam. I'm with Powerex. We are a wholly owned marketing subsidiary of BC Hydro.

My comments today touch upon a few of the improvements that Fong had mentioned about the RPS program and answer some of the questions I think Commissioner Bohn had made earlier.

And our perspective, Powerex's perspective, on California's RPS program comes from maybe a different one than what's contemplated in the legislation or in the actual practical implementation of the program. And that is of a renewable aggregator.

We do not own any renewable facilities. We have rights to the excess renewable capability of the BC Hydro system, as well as other northwest supply. So, you know, what I bring, comments to you today, gives you some practical realities, maybe addresses some of the nonstandard issues, and some of the flexibility that can be gained and that would help California meet its RPS goals. And also improve upon renewable development across the west, as a whole.

The first issue, and I've limited it to three priorities, as staff had advised me to do so. And that's on the contract failure and contracting process.

Certainly what we have found from an aggregated perspective, the contract limit or requirement of ten years or greater, does put an impediment on contracting to allow a more flexible limit, as Mohammed had mentioned in terms of LA's approach to, you know, multiple term products, five, ten, 15.

From an aggregator's perspective, like Powerex, to offer products with those shorter terms from our portfolio of renewable resources, such as small hydro, will provide this incentive to further build up our renewable base as a composite of different term products.

And from a risk perspective, certainly we find that, you know, with the developing nature of not only California's RPS program, but programs across the west, you know. The shorter term contracts allows both the buyer and seller to mitigate some of that risk and provide some benefits in that regard.

The second issue that I want to touch upon is related to the deliverability requirement of out-of-state generators and Fong had touched upon that, as well. And, you know, coined the phrase of the banking and -- I guess banking and shaping term, in which we had brought that issue forth to the Commission years ago where we thought that the current guidebook didn't reflect sort of the realities of energy exchanging hands between control areas.

And, you know, we certainly continue to feel strongly that improvements in that area would enhance offers into the California RPS program from out-of-state suppliers and aggregators like Powerex.

There is one issue specifically I want to address that was raised in the consultant's report. And there was a recommendation in the report where it mentioned that the consultant report recommended that there would a relaxation to the delivery for out-of-state generators, allowing delivery to nearby market hubs and substations with utilities managing delivery risk into the state.

Powerex's views on that has -- we've echoed the same in the CPUC's resource adequacy requirement, where we've stated that it may not be the cost effective way to insure renewable energy delivery to the IOU customers. And the reason why we say that is that Powerex believes that the out-of-state supplier or aggregator may be in a better position to manage the congestion risk and take on the obligation to deliver the energy into the California ISO control area, resulting in lower costs to the IOU customers.

I guess, in general, what our view has been is that allowing out-of-state supplies some more flexibility in how to deliver the physical energy, renewable energy will result in more renewable generation being offered, at more competitive prices.

And whether you term a phrase banking or firming or a monthly type true-up, or a more extended true-up of renewable energy, that will again enhance offers to California utilities.

Lastly, you know, Powerex believes that from a practical point of view there are some improvements that can be made to the certification process. It also recognizes, you know, different model of renewable supplier from an external source.

And that's the renewable aggregator where currently right now certification is explicitly required from the owner of the facility. And doesn't contemplate a third party would certify an out-of-state facility or want to register that facility, where they have contractual rights, but not physical ownership rights.

And so in closing, you know, we believe that there is significant renewable potential, and I think the Commission has recognized that in terms of potential outside the State of California, specifically in the Pacific Northwest, in British Columbia. And that that renewable potential can be tapped into to meet California's requirements, as well as enhance the resource mix for the entire western interconnection.

Thank you very much.

COMMISSIONER BOHN: May I ask just one

question. It's hard for me to understand how you can have two people managing congestion. And I don't doubt, and I may not understand it, I don't doubt that if you were aggregating from a whole series of sources you would be in a position to manage congestion.

How would you work with the ISO or whoever else you'd work with? Would you be willing to subject yourself to their management of the congestion process? I mean I just don't know how you do that.

MR. LAM: Well, I think the point -- I think my understanding of the consultant's report was simply to say that the utilities would pick up the energy outside the border point, and bring it into California. Whereas, what we believe is that a better outcome may be, is to allow the supplier responsibility to deliver into the control area.

And thereby, as you said, take on the congestion risk, managed, you know, through the different points. But still be required to obligate to deliver into the utility service territory.

MS. HAMRIN: Thank you, Jeff. Cliff Chen from UCS.

MR. CHEN: Thank you, Cliff Chen, Union of Concerned Scientists. Appreciate hearing the comments of all the other people in the room. Agree with a lot of what's been said.

I don't have too much to add, though I will note that I do think that reports of the imminent failure of the RPS are a little bit exaggerated.

It's pretty clear that there are significant problems and challenges to overcome. And it's pretty clear that the consensus among people in the room is that the biggest challenge is physical infrastructural one of transmission.

While I think it's good and useful to talk about short-term contracts and unbundled RECs, in the end it all comes back to transmission.

And it's not clear to me that overhauling the entire structure of the RPS at this critical juncture in the program will produce preferable results as far as the 2010 timeframe goes.

There have been positive developments at the PUC and at the ISO. And there have been over 2000 megawatts of contracts signed. There will probably be dozens more signed this year. With 2010 just looming around the corner, I don't know if now is the best time to make significant overhaul changes to the program.

So I would just submit that rather than trying to completely rebuild the road that we're on, this is the road that we find ourselves on for 2010, I believe, for better or for worse. And let's try to smooth that path instead of completely rebuilding it.

Thank you.

ASSOCIATE MEMBER GEESMAN: I'm not going to let you off quite that easily, Cliff.

(Laughter.)

ASSOCIATE MEMBER GEESMAN: Let's assume the politics stay the same, and let me summarize those as the utilities and other customer groups will remain adamant that we don't pay too much for renewables.

Do you think the existing program structure is a good foundation to move beyond 2010 to the 33 percent 2020 goal that has been adopted by both Commissions and the Governor?

MR. CHEN: I do think that there will be significant changes needed to the structure, but

I'm going to withhold commenting on what those changes are at this time.

ASSOCIATE MEMBER GEESMAN: Okay. So you did get off.

(Laughter.)

MS. HAMRIN: Last, but not least, Rick Counihan.

MR. COUNIHAN: I like to think last, but best, but maybe I chose the wrong seat.

Commissioners, thank you very much for having me here today. My name is Rick Counihan; I'm with Ecos Consulting. But today I'm representing the Alliance for Retail Energy Markets, which is an alliance of six energy service providers who provide retail electricity services here in California.

I'd like to start my comments by saying that the AReM members are committed to complying with the California RPS 20 percent requirement by the year 2010.

Most of the AReM members are active in states all across the country which also have RPS requirements. And they meet those RPS requirements in those other states.

AReM has provided a detailed proposal to the Public Utilities Commission on ESP compliance. That was one of the issues brought up earlier today. John mentioned it, and I think Pedro mentioned it, as well.

We have provided a detailed proposal that has the ESPs meeting the 20 percent requirement by 2010, along with incremental increases every year between now and then; a detailed reporting and verification process; and penalties to be assessed in the event of not achieving it.

I will not -- at Jan's request I will not reiterate all the details, but I probably will attach it to our comments so you can see how detailed it really is.

And in response to the staff questions and the memo that came with this, in terms of getting ESPs to participate, the single thing that could happen to make it happen the fastest is for CPUC approval of that proposal.

I will say, however, that I believe the RPS is way too complicated. And I think there are some incremental things that the Commissions, different Commissions, could do to make it less complicated without overhauling the entire system.

And I'll give three suggestions here just in the spirit of the staff memo that came with this.

Simplification number one. Why do we have two RPS targets for every LSE? The data indicates that we're a little over 10 percent towards the 20 percent goal. No way are we going to get the 20 percent without significant new renewables.

In addition, if the existing renewables go away, that's going to make it that much harder. So why are we measuring these two separately? I think an easy simplification, and I know, Greg, you're with me on this; we've talked about this before. Why not have one target, 20 percent, instead of adding an incremental and a baseline target.

Simplification number two. What's all the focus on the length of the contract terms? I think from a public policy perspective the outcome that you want is either a contract signed, or perhaps even actual megawatt hours generated. What do we care if it's a six-year contract or a 13-year contract or a nine-year contract?

Third simplification. Following on V.

John White's comments, I would recommend that we move to a RECs-based compliance once WREGIS is up and running. There are 19 states in the Union, plus the District of Columbia, that have RPS standards. Of those 20 entities, those 20 jurisdictions, 17 of them either require RECs for compliance, or allow RECs for some portion of their compliance.

California is the only state in the Union that has an RPS that has competitive suppliers that doesn't, at this time, allow RECs. RECs provide flexibility and liquidity, both for the generators and for the LSEs.

And I think an important thing that's missing from the debate in California is that the use of RECs, they're an accounting mechanism. The use of RECs does not prejudge a lot of the policy issues such as geographic eligibility. Where you have to connect, where you have to deliver.

Doesn't prejudge technology eligibility. It doesn't prejudge new versus existing. It's an accounting mechanism that makes it easier for everybody to do business. And I commend the CEC for funding the WREGIS effort and keeping that moving forward.

So, I think those are three concrete areas where we can simplify the existing process. Does that solve all the problems? No. But we're suppose to be brief, and so I'll just suggest those three simplifications and let it go at that.

Answer questions, if you have them.

ASSOCIATE MEMBER GEESMAN: We've certainly been advocates of a REC system at the Energy Commission. And Commissioner Peevey is well known for having attempted to fall on that hand grenade at the CPUC. Been directed by certain of the legislative leaders that the PUC may not have that authority.

You indicated, though, that you don't feel a REC system discriminates between new and existing projects. And the argument has certainly been made that RECs do not assure the construction of new renewable projects.

And I'm curious as to whether you can point to areas of the country where it's been demonstrated beyond dispute that a REC system has, in fact, led to new construction.

I'm familiar with the theoretical arguments. I'm not clear on the empirical. And I'm looking for that.

MR. COUNIHAN: Yes, well, I'm actually very happy that you asked that question because for the AReM members Ecos looked at renewable development in the other states across the country that have RPSs.

And in fact, what you see is that while 17 out of 20 jurisdictions allow RECs, there is new renewable development in all of those. And the one that a lot of people talk about that's obvious is Texas, where all compliance is based on showing up with RECs at the end of the year to prove that you did what you did. And they've done a couple thousand megawatts of new developments since 2001.

But if you look at the other states, also, you can see there's new renewable development in virtually every state with an RPS, and virtually every state allows RECs.

And I would be happy to append that study to our comments for the use of the Commission.

ASSOCIATE MEMBER GEESMAN: We'd appreciate it.

CHAIRPERSON PFANNENSTIEL: Rick, on your first simplification point where you would only measure at the 20 percent and you wouldn't worry about the interim targets.

MR. COUNIHAN: Excuse me, that's not what I meant. What I meant was that, yes, there would be interim targets, but you wouldn't have a separate in 2008 incremental target and a baseline target. You'd have --

ASSOCIATE MEMBER GEESMAN: This is IPT versus APT.

CHAIRPERSON PFANNENSTIEL: Right, right.

MR. COUNIHAN: Right. That's correct. My recommendation is that you have one target for 2008; one target for 2009; and one target for 2010.

CHAIRPERSON PFANNENSTIEL: I got it, thanks.

MS. HAMRIN: John White, you have a comment?

MR. WHITE: -- about the RECs issue is that I think one of the things that's changed that may give us some mechanism for integrating this discussion is the debate on the climate targets and the new generation performance standard contained in Senator Perata's SB-1368, both the tracking of the compliance with the climate targets and the tracking of the compliance with the generation performance standard is going to involve similar activities as the tracking of transactions between sellers and buyers of renewable energy.

It seems to me that rather than waiting for WREGIS, which has taken much longer than it should have to develop, is that I think the Energy Commission should build upon the platform that already existed at one time for tracking retail claims, and begin looking at trying to track all these various similar kinds of transactions in a way that is both transparent, and at the same time, protective of commercial and confidential information, all of which is going to be required for each of those separate pieces.

And I think while there is still some controversy about whether the PUC can act on its own to allow the use of, limited use of RECs for RPS compliance, the tracking function between instate/out-of-state coal, imports, renewables old and new, is all going to end up being similar kind of stuff. And architecture seems to me to be available to make that happen.

MS. HAMRIN: Dan Adler.

MR. ADLER: One related point and it goes back to the rebuttable presumption. I think I was a little bit flip in my answer that it is a rhetorical device. I meant that that's really all it is so far, but in the long run I think it's an important procurement mechanism that allows for the integration of all these various issues.

You can have a REC market; you can have a carbon market; and really importantly a carbon price in the general utility procurement process that, over time, again in theory, makes the RPS as a separate program, less and less important.

That, I think, in the long run, is where this market-based approach, if that's the path we continue on is where we're heading.

MS. HAMRIN: Anyone else who -- yes, Pedro.

MR. PIZARRO: Just a ten-second comment is I think as we look at whether it's Rick's or Dan, I think your comments on how these things get integrated, a key thing that I want to emphasize again, is that we need to make sure that we're employing these tools in a common way across all load-serving entities who are having to comply with them.

And so, you know, Rick, I think to your point about the focus on long-term contracts, the realities of today, we have a long-term contract requirement on utilities. To the extent that the Commission decides that it wants to try out a REC-based approach, then let's try that out, but let's make that accessible to everyone and not have differential requirements, a long-term requirement on utilities, and others being able to get, you know, satisfy their RPS requirements with a one-year REC demonstration.

Again, similar to the debate that we have in resource adequacy.

MR. COUNIHAN: And, Pedro, I would say that I totally agree that IOUs should have one target, not two targets. Everything I said I didn't specifically say ESPs, but I think simplify the program.

ASSOCIATE MEMBER GEESMAN: I have two gentlemen on the phone that we'll take questions from before we go to a break.

First, Juan Sandoval from Imperial Irrigation District. Mr. Sandoval?

MR. SANDOVAL: -- on behalf of IID, in regard to what we have done in meeting the RFP, you know, the RPS standards mandated by the state.

First of all, you know, a couple of years ago our Board of Directors passed a resolution to voluntarily comply with the state's RPS. And last year in October 2005, IID submitted an RFO for green energy. And we have received several responses and we are really working on a short listing of proposals.

And currently we are considering acquiring 500,000 megawatt hours of energy. And this is going to mean acquiring about 65 megawatts of a capacity factor of 85 percent. And we'll expect to meet the RPS by even a 30 as 2008.

Also, we have about 85 megawatts of small hydro generation. This is several units of lower than 30 megs, these fall in the Old American Canal. And we believe that this small hydro will qualify also to meet the RPS.

So, aside from that, you know, we have made significant efforts in other arenas like the transmission efforts. But I'll leave that conversation for later discussion.

ASSOCIATE MEMBER GEESMAN: Thank you very much. John Galloway, Union of Concerned Scientists.

DR. GALLOWAY: I really don't have that much to add except to say that, maybe reiterate and try to drive home the point that I think supply issues and transmission issues really are at the top of the list. I know a lot of the questions that were identified for this afternoon's workshop really sort of look at architectural features of the program.

And I think more important than trying to come up with, you know, whether or not we synch-up solicitation cycles or make them annual or establish a schedule, I think rather than digging around in that level of detail, I think addressing issues that get more developers into the process, whether it's to look at the lessons-learned-type exercise that the PUC has been beginning to undertake to look at how the solicitations are going, and whether, you know, issues around credit requirements and the posting of credit collateral requirements, those types of things.

But also I think there's some bigger picture issues around what's happening at the federal level. We've seen the boom/bust cycle in the production tax credit, and the investment tax credit causing a lot of consternation among developers as they've either begun negotiations with purchasers here in California, or they've been hesitant to even enter because of the financial risks that exist.

And I don't think that those issues are ones that exist within the architectural features of the program that either the CEC or the PUC can necessarily take on.

But I think ones that are certainly within the purview, particularly of the PUC, and to some extent the CEC, are transmission. I know that's part of a separate conversation.

So I would sort of put, reframe how we're talking about the very specific features of the program. Focus on those big-picture issues. And getting, you know, getting the business climate right here in California.

With respect to the use of RECs I know there have been several comments on the panel just a few moments ago regarding going to a REC trading regime to create more flexibility within the program. UCS certainly agrees with that.

What I would turn the question back on to the CEC, and particularly to staff, is the ability of the type of architecture that Mr. White described for the retail credit program to handle those kinds of transactions today.

I would appreciate hearing from staff as to the capabilities of, you know, what you have in place right now to actually do that.

What I would hate to see is that we end up spending a lot of time creating, you know, having the staff at both Commissions go round and round trying to create something new under the assumption that it's not new, it already exists.

Because from my experience both of having worked at the Commission watching the verification process of resources to establish the baseline for just the IOUs, how to say nicely was an arduous process, to then try to undertake something where the Commission Staff are having to verify REC transactions that don't fit into the nice neat box that we have presently with the bundled transactions that the IOUs are entering into.

I'm just afraid we end up spending a lot of resources in a direction that WREGIS is supposed to inherently capture. Now, granted, that timeline has been pushed back further than people have expected.

So, I guess it would be helpful, not only for myself, but for other stakeholders on this panel, to hear how that capability might actually work, irrespective of the question of whether or not the PUC actually has the authority to allow unbundled RECs.

So, I would pose that as a question.

ASSOCIATE MEMBER GEESMAN: Yeah, I would only answer that the same people designed the state software procurement process that currently WREGIS is mired in that designed the CPUC transmission licensing process that Tehachapi and other important projects are mired in.

The capabilities that can be added onto WREGIS are theoretically pretty broad, but navigating the software procurement process that has been in place since the Oracle scandal is not a very timely process.

I mean once WREGIS is lodged at WECC it may open up more opportunities for add-ons. But, again, it's a time-consuming process if you're going through the State of California process.

DR. GALLOWAY: Sure. And, Commissioner, my comment was focused on the sort of pre-WREGIS idea of going to a REC regime in absence of WREGIS being available. Let's say WREGIS were to be pushed to the end of 2007, would there be an interim, the capability of establishing an interim tracking system. I think there's a belief that permeates that that structure already exists and is left over from the retail choice era.

And I guess what I'm asking, the question, and maybe positing that it may not be as readily off the shelf as some make it out to be. But that's what I'm -- I guess I'm wondering if, you know, some of the staff there that have worked on the consumer credit account, that dealt with those kinds of tracking issues, could, you know, offer some insight. If not now, you know, maybe at some point in the coming weeks.

I think it would be helpful to sort of help all of us who are trying to frame the debate before both Commissions, and particularly before the PUC.

ASSOCIATE MEMBER GEESMAN: Well, rather than put Tim Tutt on the spot right now, --

DR. GALLOWAY: Oh, why not?

ASSOCIATE MEMBER GEESMAN: -- why don't we take that under advisement and give you a more well-considered response. My belief, from when we operated that before, is if you can live with about a 120-day lag, that should be within our capability to do, based on past performance.

DR. GALLOWAY: Well, Commissioner, that's appreciated.

ASSOCIATE MEMBER GEESMAN: And we'll provide more on that in the future, John.

One comment from Bob Burton before we go to a break. Bob from the Insulation Contractors Association. He's been waiting patiently.

MR. BURTON: -- I don't claim any expertise (inaudible) -- but there were two items that were discussed today that I do have some expertise, and I'll make a very brief comment.

First of all, in my previous life I was a Corps of Engineers officer who spent a number of years in contract administration. And it is not a given that a well-established producer will necessarily be the best producer. He might merely have the best, most aggressive and unprincipled lawyers. So, when I was a contract --

ASSOCIATE MEMBER GEESMAN: An oxymoron.

MR. BURTON: -- and I knew a contract was going to be administered by me, and the winner was a small contractor, I would breathe a great sigh of relief because I'd be quite certain that this guy is fairly likely to work on the job rather than fly-specking the contract.

So, since these contracts that you're talking about are going to be written from scratch, it's my firm belief that they will be easily fly-specked. And therefore -- since they're being negotiated. And therefore I don't encourage a process that will seek out the most established contractors.

The other subject that I would discuss, having been since 1965 a lobbyist and a close observer in the Legislature, to briefly summarize our tax system in California varies greatly in its income with the economic and top-markets -- cycle. But the State of California's Legislature has never recognized this.

So we have a structural defect deficit which runs anyplace to $2 to $8 billion a year, depending on whether it's a good year or a bad year.

The way they make this deficit up is by borrowing. And most commonly they borrow from anyplace they got their hands on. For example, the transportation fund routinely loses most of their money to that. And it's called borrowing, but in fact, it's theft, because they have never paid any of it back.

So, if you have any hopes of setting up this escrow process the only way you can do it is by very publicly embarrassing a lot of people, and embarrassing politicians is usually not a productive process for other relations with those same people.

So my advice is you're probably stuck with not getting this money put into escrow. And that's my brief comments. And I did not come to -- did not really expect to make any. I thought I would -- but since you did discuss a subject I knew something about, that's what I came about. If a person has a question I would be happy to answer it. I'm sorry if I have not been fully candor -- full of candor.

ASSOCIATE MEMBER GEESMAN: Thank you, Bob. Why don't we break until 4:00.

(Brief recess.)

MS. DOUGHMAN: To start our discussion on transmission issues, David Withrow from the California ISO will talk about their petition to

FERC. And so here he is.

MR. WITHROW: Thank you. David Withrow with the ISO. I'm here with Robin Smutny-Jones, who is coming back shortly I think, and Dave Hawkins. And I'm just going to talk briefly about one component of the ISO's renewables initiative that was explained to our Board at the last Board meeting involving the ISO's intent to pursue a petition for declaratory order at FERC regarding renewable transmission.

As we all know, the ISO tariff currently reflects current FERC policy which divides new transmission facilities into sort of two buckets, one network facility that provides some degree of integration with the ISO integrated grid, which are justified by reliability or economic reasons. And the second bucket of gen-tie or direct interconnection facilities that are required just to interconnect the generator with the grid. And those costs are borne entirely by the generator who's developing the facility.

Therefore, under a number of complaints and a great burden of proof that this is providing a distinct barrier of entry for renewable development, the ISO is considering a category of transmission that is distinct from network facilities that are approved for reliability or economic reasons. And that would be the basis of our declaratory order.

It would include a proposal for a cost-recovery mechanism by which the costs are initially allocated systemwide through the ISO TAC charges, and then recovered as renewable generators come online.

Again, the ISO anticipates a two-step process where we would seek a declaratory order with FERC that provides policy guidance from FERC before we take the additional, more time-consuming and detailed step of filing an actual tariff amendment before FERC. We figured it would be a more efficient use of our time and our stakeholders' time to get the policy guidance from FERC established before we take that additional step.

There have been recent regulatory developments in this realm. Edison filed a similar declaratory petition which FERC rejected last year; and more recently, the PUC has issued its own order for a backstop approval at the retail level for recovery of transmission dated for the RPS standards.

The ISO anticipates that our policy proposal would be quite similar but not identical to the PUC backstop authority.

Some of the key policy issues that have been identified in a whitepaper that was recently posted on the ISO website includes a, if you will, a straw proposal for some principles that would define the facilities that might be eligible for this distinct category of transmission.

Namely that there be high voltage bulk transfer facilities that are currently not classified as network upgrades. And that are expected to be placed under the ISO operational control. And that specifically they would be built in an area with significant potential for renewable resources. And the ISO would likely rely heavily on the CEC and PUC to identify those specific renewable areas.

The second part would be a cost-recovery mechanism which suggests rolled-in rate treatment of unrecovered cost for these transmission facilities which would be paid initially by all users of the ISO grid. But that, over time as developers latched onto the grid, that they would reimburse all ratepayers for their share of the line as the generation comes online.

Just briefly, the policy -- or the process that we'll be following leading up to this filing of a petition, we've already informed our Board and got some guidance from them. We posted a whitepaper about a week ago.

We have a stakeholder meeting tomorrow morning in Folsom from 9:00 to 12:30 p.m. in which we hope to get both a lively discussion and some written comments within a week that would help guide our development of these principles and the declaratory order.

We anticipate seeking Board approval for the principles for the declaratory order at the very next ISO Board meeting on August 3rd. And to file the petition soon afterward.

In closing I'd suggest we fully intend to work very closely with the CEC and the PUC in developing, frankly, the best legal arguments that we can muster and see what we can -- see what policy guidance we can get from FERC.

ASSOCIATE MEMBER GEESMAN: I think this is a terrific initiative. And want to thank you and Yakout, in particular, for doing the work that launch it. I think the State of California has a lot at stake in your success with this. And I hope that message is not lost on the various munis who tend to be late converts to the renewable cause, but seem to file form oppositions to most of your various proposals at FERC.

I think all of us need to work together to make certain that the state's interests prevail here.

COMMISSIONER BOHN: Can I ask a question just for a second. Presumably there's some reason to believe that the FERC will grant this request. Are you asking, as a newcomer in this whole process, are you asking the FERC to change an articulated policy? Or are you asking them to clarify a policy which is currently ambiguous?

MR. WITHROW: It is possible, depending on how we frame the petition, that this could set some new national precedent for a specific category of transmission.

I would note, there's been some change in the membership of the FERC since Edison's petition last year. There has been increased focus on renewables and the efforts that transmission can contribute to renewable generation over the last year. And there may be hope that more refined and careful legal arguments may prove to be a different result compared to what happened last year.

The ISO is pretty open to suggestions. And that's one reason why we're soliciting very strongly some stakeholder input from this community and from as many people as we can get, to devise the best legal arguments that we can get.

COMMISSIONER BOHN: So I translate that to mean you're hoping to change the existing policy by virtue of marshaling good arguments that will form a national precedent, as opposed to some narrow legal exercise?

MR. WITHROW: I think that's the directions of our management right now. And I would reiterate, this is a very high priority, is very intensely focused and involved in this initiative.

ASSOCIATE MEMBER GEESMAN: Thank you, David.

MS. DOUGHMAN: Our next presentation will be sort of a joint presentation. We have Dave Hawkins sitting at the table and Robin

Smutny-Jones actually giving the presentation. I believe Dave Hawkins will be available to help answer any questions.

MS. SMUTNY-JONES: Good afternoon. I'm Robin Smutny-Jones impersonating Dave Hawkins, who came down with a -- he's not contagious anymore; you don't need to leave the room, but he lost his voice, so I'm Dave's voice. And he's going to channel information to me as I'm up here speaking.

Chair Pfannenstiel, Panel Members, thank you for having the ISO here today to address this really important topic. And Dave Withrow just took the words out of my mouth that I was going to lead with, which is the intense focus that the ISO is placing on helping the state meet the RPS goals, and all the things that we can do to further that, you will see a great deal of dedication to.

This is from the Board level to the officers to management and everyone down. We're very committed to this effort. And Dave will croak out some help if I need it.

As mentioned, this is a top priority for the Board to meet the RPS goal. There are three main areas that the ISO is engaged within that affect the RPS goal transmission planning as the obvious one. That's the sort of finale of the day. Everybody's been talking about that being one of the key pieces missing to make all this come together.

Markets and operations also become critical. How we structure the scheduling requirements; how we help the PIRP program, which is participating intermittent resource program, become better over time so we can accommodate the resources into the grid. Those are the areas in which the ISO can contribute.

Here's a chart that shows basically existing and potential new renewable resources. It's based on some CEC material. And you see there's a lot of green, there's a long way to go to get to these targets. And this is available to you to look at. I don't think I need to spend a lot of time talking about it unless you have specific questions.

I definitely don't want to talk very much about this chart. It's really busy, and it's getting late, and I'm going to try and keep you all on time, but, you know, I'd love to go into depth on excess marginal loss revenues and MRTU and ramp forecasting, but, gee, there's just not enough time.

(Laughter.)

MS. SMUTNY-JONES: I think I want to make one more point before opening up for questions from ISO and obviously we'll be available to help with the Q&A discussion that's coming next.

Our efforts to potentially bring about a new paradigm with respect to how transmission gets approved, including this new category of transmission. By the way, we are trying to come up with a new acronym, and this is the perfect set of brains to help with that effort.

And yesterday we came up with TRG, but I like TARGET, so it's the transmission for renewable generating tors. If there's -- I'm sure there's a better acronym out there somewhere. But we liked TARGET and we were trying to force it in there somehow, so please help with that effort.

The effort that the ISO undertakes that Mr. Withrow spoke of is critical and the help support that we get from the state regulatory entities, from the stakeholders, is extremely -- utilities, everyone, it's critical. The ISO's in a unique position to provide regional planning guidance to the state.

We have a perspective of the grid that's larger than just any single utility. We can't do it alone. We have to have help from the regulatory entities, the utilities, investor-owned and municipal utilities alike. We'll continue to try and bridge whatever jurisdictional turf issues we've had in the past. We simply don't have a choice but to do that, by the way. We must figure out a way to coexist all together and move the state along.

But we are counting on the state being the pillar underneath us with respect to the arguments that we put forth to FERC. And we can't over-emphasize the help we're going to need from you all.

Thank you. Look forward to questions.

MS. DOUGHMAN: Our next speaker is Mohammed Beshir from the Los Angeles Department of Water and Power. He'll provide an overview of the green path transmission project.

MR. BESHIR: Good afternoon. Thank you, Commissioners, again. I have just a brief discussion on the green path project that, as you know, the LADWP, Imperial Irrigation District and Citizen Power have been engaged in development of transmission project in the -- with the main goal of accessing the geothermal resources in the Imperial Valley.

So, in general, the green path project consists of three components. I just want to make sure you understand those distinctions and the differences.

We have what we call green path north transmission project. I'm going to give you a pictorial of that shortly. And we also have the green path internal IID upgrade. And we have the green path southwest transmission project.

So those are three coordinated project under the green path project. But there are some distinctions I need to make.

The main goal of the projects, of course, is to access the 2000 megawatt of potential geothermal resources in the Imperial Valley, as was validated in the study done by the CEC in conjunction with others not long ago.

LADWP interest is strictly on the green path north transmission project. So I just want to make that distinction.

The pictorial I have on the screen is essentially probably you've seen this thing. This is just to describe the different components of the green path. Have a pointer here? Okay, I guess I -- okay, thank you. Okay, that's okay. I can use this cursor here.

What we have here is this is the northern green path north. And the northern point essentially goes from this area, Devers or Indian Hills, all the way to a transmission network LADWP owns.

We have the internal IID upgrade, which is to facilitate the development and enable the delivery of the geothermal resources in the Imperial Valley, as well as the transmission going south and west, which is a green path southwest, which is essentially IID and Citizen has been working to develop.

For LADWP the interest is in the green path north, interacting to Indian Hills or Devers area. Guess we are still evaluating a ways to interact and interconnect that station, as well as going up to our -- to existing to 87 system and building a new transmission line with a potential interconnection to the Edison system or California

ISO in that area.

The project information, it's a 500 kV transmission line for the green path north. Potentially 100 miles, depending on the configuration we choose. It could go at Devers or somewhere in the area of Devers; or close by to that station.

We're also looking at some other upgrades in our existing 287 line to a 500 kV to be able to make those interconnections and make the power flow the way we want it.

Additional transmission expansion into IID system to access the geothermal resources. And the potential from 1000 to a 1600 megawatt project. Definition, ownership, LADWP, we're looking about 80 percent with 20 percent being others.

Project, we are looking to be in service in 2010. Costs, approximately $300 million. We are in the WECC rating process. We have obtained phase one. We are in the phase two process. And we are working through the environmental process and preliminary design.

Some of the key issues is, of course, routing, transmission routing is a consideration.

We are looking at many different areas of station, where it's going to be. Rating issue, as I mentioned. Earliest participation agreements. And power delivery.

These are some of the transmission routes we are looking at with many many different challenges on different routes we select. We are looking at the different opportunities, and issues with environmental and, as you can see, we do see potential likelihood moving the project up, going on the green side on the north, which has less environmental issues.

But I'm just showing you, this is really we are working very hard trying to get the project going on schedule. This is the project schedule we're working on. The green is where we are today. And we're working hard on system planning, preliminary transmission design work, station design work, environmental study, contract development. Hopefully with those done, we'll move on to detailed design, procurement, construction and we try to get in the schedule into by 2010.

Continue with initial some next steps for us. Continue with the environmental, system studies, as well; and also doing some preliminary design, sending our RFP for additional help from resource point of view. And also to get in some approvals internally within our system.

So that's, in general, what the green path north is, and what the Department has been working on, try to make.

I just want to note, this is not the only transmission project LADWP was working in conjunction with renewables. As I mentioned earlier, we are working on the -- get into the Tehachapi. We building today a ten-mile line, as I mentioned. And also on the STS.

In addition to that we're working internal to our system to interconnect as a renewables as they come. Thank you.

MS. DOUGHMAN: Jim Avery from San Diego Gas and Electric was planning to speak about the Sunrise transmission project, but I believe he -- so, please go ahead.

MR. AVERY: I snuck in. I didn't bring any presentation materials because I think you've probably seen it all already. What I wanted to do is to take the opportunity and talk about the Sunrise power link, and in conjunction with the green path southwest.

Just a few short weeks ago San Diego Gas and Electric signed an agreement with the Imperial Irrigation District, along with Citizens Energy, to collaborate on the development of the objects to make the overall project a reality.

The opportunities, and I sat here this morning or earlier this afternoon and had an opportunity to hear all the things that were said about the development of renewable energy and what is needed to promote further development of renewable energy.

And first and foremost what I heard and what I have seen is that we need transmission. And I don't think anybody really disputes that.

For San Diego we have, and you heard Terry Farrelly talk about this morning, that we have been very aggressively pursuing and are very optimistic that we will meet or exceed the state's goals of 20 percent by 2010.

But the only way that we see that we're going to be able to do that is with the advance of transmission. And toward that end we started a project that will satisfy several things on our system.

Number one, the ability to satisfy the reliability needs that are covered under resource adequacy by the CPUC. And the ability to also meet our 20 percent goal for renewables.

And with that in mind, when we started looking around for the right place to go to meet both of those objectives, Imperial Valley was the logical place for us.

We have already signed contracts for several hundreds of megawatts of renewable energy in Imperial Valley that will be delivered across the Sunrise power link.

And we are negotiating and very close to many hundreds of more megawatts that will be delivered across that line. And in the end, we will, before this project ever gets approved, probably have well over 1000 megawatts that will be delivered across the Sunrise power link, all renewable energy.

And that's a combination of solar power, not just from one developer but from multiple developers; wind resources and geothermal resources. And the potential for biomass, as well.

And we've had discussions with all of

these, and we will continue to do that until we meet those goals.

If I look at this project it is no small undertaking for us. It is a major undertaking. We have started the process several years ago, and looking at potential for routes. We have had an extensive program out in the public looking for public participation, public awareness, and actually getting the public to help us find the right location for the facilities and the right types of facilities.

We have been doing an extensive amount of work preparing to file our proponents' environmental assessments, which will be filed in the first week of August with the California Public Utilities Commission.

And with that, I open myself up for any questions or comments or observations.

ASSOCIATE MEMBER GEESMAN: Jim, we've talked about the project at a number of our hearings before. Obviously identified it as a priority for the state in the 2005 Strategic transmission Plan that was a part of the IEPR.

It's pretty clear all these projects are always going to encounter localized opposition.

And we're no strangers to that in the power plant siting process.

But I wonder if, in your experience thus far with the Sunrise project, if you're encountering more regional or statewide interest that have voiced opposition to the project.

MR. AVERY: I think overall, when we started out the process we did this differently than we did when we did the Valley-Rainbow process. In that case we followed what I'm going to call the traditional utility approach. And that was behind closed doors we figured out what we wanted, where we wanted it, and then we filed an application and went to the public.

In this case long before we ever filed our initial applications, we started a public outreach. And that public outreach was long before we identified a corridor. And we stirred up a lot of opposition out of fear.

But I think that's not necessarily a bad thing, because we've learned an awful lot from that process. And in this case there are segments of transmission facilities that we're proposing to build underground because we recognize the impacts it has in particular areas.

We've also changed the routing significantly through the course of events in dealing with the communities. We've learned some things about some Native lands, Native American lands, and where there are some burial sites. We've learned a lot about the existing transmission; where the corridors were. And we identified that we created problems 80 years ago when we built transmission, and this is an opportunity to fix some of those problems at the same time.

And we've been working very diligently with state agencies, with federal agencies, with virtually anybody who's willing to talk to us. And what we've found is we're not necessarily very popular by some special interest groups.

But I think in the end what we're trying to do is take the opportunity that we have before us today, and that is like a lot of the utilities in the state, we are short on capacity. And if we can take the opportunity and fill that deficiency first, with energy efficiency, demand response and renewables, we think we're doing the right thing.

But we have a window of opportunity that if we don't do it today we're going to have to fill it up with gas generation, and then we'll be in the same position we were in ten years ago when everybody was saying there's no room for renewables.

Well, if we pursue it today, we get the transmissions in place today, we can actually get the contracts today.

One of the things that I heard this morning with great interest, and I absolutely agree with the notion that there are a lot of small development projects out there that the developers don't necessarily have the experience or the capability to get through the process that we put them under. And that process is a big process; it's not just the utility, it's all of the different constituents who have an interest in this.

And what we've been trying to do to deal with that is actually help some of the project developers get through that process, dealing with federal lands, dealing with state lands, dealing with community issues and so on.

But I like the things that I heard this morning about the notion of perhaps crating an enterprise in the state that also takes on a role of helping the developer to actually come to reality. No one wants to see a project fail. And in our case, we have had one project fail, and it was because we didn't do enough to help that project get through all of the red tape they had to get through.

Now, they're coming back to us. And, in fact, I'm optimistic that they ultimately will develop. They've learned an awful lot, and we've learned an awful lot through the process.

But if I look at the transmission system, it is hopefully inadequate to try to capture the opportunities that are around us today. And if we don't do something today we're going to lose those opportunities again.

And I think the Sunrise power link and in the work we've been doing with Imperial Irrigation District and Citizens Energy is a great opportunity. I mean here's a line that is going to provide 1000 megawatts of reliability to San Diego. Why can't we fill that with renewables today. And that's the goal that we've set out is to do exactly that.

And I think there's just a wonderful opportunity for the state and it's not just what we're doing, it's what others are doing. And we need to do everything we can to remove those barriers.

But getting back to your first question, is the opposition localized and it is specific on one or two points. I think for the most part it is. I think that there's a lot of misinformation around our project and other projects that suggest that we're doing some bad things.

But I think that those people who have come and met with us and looked at what we're trying to do understand that this is an opportunity that we can't give up.

I will tell you there's a hot point, and that is we need to go through the Anza-Borega State Park. And questions have been asked to us, well, why don't we go around the park. Well, anybody who knows anything about the Anza-Borega State Park in San Diego knows it is the eastern border to San Diego. And there just is no way around it.

So the course of events that we've traveled or decided here is we have an existing corridor through the park. Why not remove those facilities and build the new facilities in their place. And work with the State Parks to actually mitigate perhaps some problems that we created 80 years ago.

And I'm confident we can do all of that. And we're willing to listen to anyone who has ideas that we can do it better.

ASSOCIATE MEMBER GEESMAN: I appreciate your keeping us up to date on that. And, as I've indicated, this is a project that we identified last year as one of statewide significance. And we intend to continue to pursue it as you go through the process.

MR. AVERY: Thank you.

CHAIRPERSON PFANNENSTIEL: Jim, how long would you say you've been at the Sunrise project?

MR. AVERY: The Sunrise --

CHAIRPERSON PFANNENSTIEL: I know it's hard to define the starting point on it, but what would you consider it to be?

MR. AVERY: The Sunrise project is something that built off of a project we started back six, seven years ago when we started out with Valley-Rainbow. And it took us three to four years to get through the regulatory process.

And in the time that when we initially

started the project and then actually got into the hearing phase, massive development happened around us. And land was acquired that was put under federal trust. And it basically closed up the corridor.

If I look at San Diego there are probably 200 miles of border that separate San Diego from the rest of the United Airlines. And out of those couple hundred miles all of it is covered now by either developed federal land, being Department of Defense, Wilderness, national forest, state park or Indian reservation. And the little bit that's remaining is built out with homes and businesses.

So we have to look somewhere; and we though the prudent course of action was to go through where we had an existing corridor. When that project failed, it failed partially because at the time, number one, a lot of the development that happened around us in the time it took to get there; and number two, there was the expectation still at the time that thousands of megawatts of merchant generators were going to come to bear.

Well, none of those have materialized. None of them. And it then put us immediately into the situation where in 2003 we issued a request for offers for grid reliability just to satisfy the reliability needs.

And in doing that we put first that we were going to take from renewable resources first. And we did. And we've entered into a number of contracts in San Diego for renewable resources. And that was after advancing our energy efficiency and demand response programs, as well.

And then we looked at the advance of additional fossil generation. But that was just a stopgap measure to buy us the time to get the transmission.

So if I look at the project today, where we are today, and we'll be filing it again in August, the project really started in the late '90s. And it's gotten us to where we are today. And it is our goal to have it in service before the summer of 2010.

CHAIRPERSON PFANNENSTIEL: Thank you.

MS. DOUGHMAN: Okay, I think we'll move to the roundtable discussion and public comments. And the moderator will be Rich Ferguson from the Center for Energy Efficiency and Renewable Technologies.

MR. FERGUSON: Yeah, for those of you who don't know me, I'm the Research Director, the technical guy, the guy who tries to keep the numbers honest at CEERT.

My colleague, Dave Olson, and I have been involved with the processes that underlay both the Tehachapi and the Sunrise projects, the Imperial Valley implementation group and the Tehachapi collaborative study group at the PUC.

So I've been in this game for a long time and now we're out at the ISO with (inaudible) death march trying to get all this stuff analyzed and to the Board by August 3rd I guess it is now.

So, anyway, I was under instructions that the PUC -- I mean that the Energy Commission and staff need the answers to these five questions that were in appendix A or attachment A or whatever they called it.

And I'm going to take some liberties here and start with not take them in order. A lot of us are going to be out at the ISO tomorrow morning to strategize on this FERC filing. And question number 9 asked for suggestions about how to do that. And since we can relay them into the group tomorrow, we might as well start with that.

The question is ways to amend the ISO tariff to allow interconnection of large concentrations of renewable generation and so on. Basically if we go back to FERC what should we ask for and how should we ask it.

So, who would like to begin, I guess, is what -- all right. Nancy.

MS. RADER: Nancy Rader, again, with the California Wind Energy Association. I'm going to rain on this parade. Excuse me, but before I clobber the ISO about this idea I first want to say how much we appreciate the transmission planning and scheduling and PIRP work you're doing, which is absolutely fundamentally important. And you're doing an incredible job on it.

So, I'm surprised about this idea that I just heard about in the last couple of weeks. But this idea of a third category of renewables transmission financing.

Just a couple of points. First of all, I don't think we need it; it's not necessary. That's why we have Public Utilities Code section 399.25, to allow the state to provide the necessary cost recovery assurances that we need to get renewables transmission built in this state. And that applies both to network and non-network lines.

The way that non-network cost recovery will work will tap any user of the transmission line, that is if a municipal utility purchases power from the constrained area, it will pay a portion of the costs through the power purchase agreement, because the generators will pay a pro rata share of non-network line costs. So there's really not an issue of costs being spread.

The issue is really covering the risk, the risk that generators will not show up to use the non-network transmission line. That risk is in our control. If we want to meet the RPS, if we do meet the RPS, the lines will be fully utilized. And there's just really no reason to go to FERC to try to completely overturn the tables, the policy framework that has underpinned FERC transmission ratemaking for the last 50 years.

We think the effort is doomed. And I can go over the legal principles if anybody cares, but we -- you know, this is deja vu all over again. We told Edison and the PUC that their effort was doomed. We were told don't worry about it. Well, they lost. Let's not do it again, folks; it doesn't make any difference that the ISO is the one that proposes it this time. The fundamental principles are the same.

And our concern is that instead of using our own 399.25 to solve the problem, we're going to wait for FERC to solve our problems instead of biting the bullet and doing it ourselves. I don't think we can afford that delay. We got to do it. We have the tools to do it. Let's do it.

MR. FERGUSON: And now for an opposing view we'll turn to Steve Kelly --

MR. KELLY: Actually not too opposing. I had concerns early on on the trunk line proposal, though I've applauded what the idea was. I had concerns that FERC would adopt that. And I was also concerned it would result in a long delay in moving forward with new transmission, which I think it did.

I guess my big question here is given the various, the PUC and the legislative initiatives to insure that there's a backstop capability for these kinds of facilities, I'm assuming that the transmission owners are not going to delay moving forward on needed transmission while this cost allocation issue is being addressed at FERC through an ISO filing.

I think that would probably be not a good thing. Because this is fundamentally dealing with cost allocation, I'm presuming we have a backstop mechanism. We ought to be able to go forward with that. And if there's another mechanism for allocating costs that is to be determined down the road, that's fine.

So I guess I really would like to hear some from the transmission owners or the ISO about whether this initiative at FERC would result in the delay of any needed transmission.

MR. AVERY: You've asked a great question. If I look at San Diego it's not an issue, meaning the transmission that we're constructing is all network upgrade and the small amount of facilities that aren't network upgrade, we have the contracts in place to fully support it.

As you look at other places, and the position that we took when this first came about was we don't support, or we did not support the notion of build it and they will come. We believe that it's appropriate to go out and permit facilities, get ready to build it. And by the time you get ready to build it you'll have the contracts in place.

And I think that's ultimately going to happen. I think you've heard Nancy say that before.

I think in the case here, I know the facilities that we've been looking at are probably going to utilize some of the projects, the facilities that we're contemplating here in the Tehachapi and other areas.

But I applaud the ISO for trying to find ways around this. I don't think anybody, and I know that we are not, holding up anything in the way of transmission and waiting for the recovery mechanism out there. But I applaud the ISO for trying to find innovative ways around this.

And I recognize what Nancy said, that there are perhaps some ways in the state to get around this. And it doesn't mean that we should just drop one and pursue one. I think that we should continue to look for all avenues to get transmission placed, and to get the proper way to allocate those costs.

MS. SMUTNY-JONES: Can I add one thing

from ISO.

MR. FERGUSON: If --

MS. SMUTNY-JONES: I'm sorry.

MR. FERGUSON: Go ahead, Robin.

MS. SMUTNY-JONES: I just want to add that, Nancy, I appreciate your comments. I think that I just want to reshape a little bit what our effort would be before FERC. And I don't view it as turning over tables of years of regulatory process that has underpinned how transmission gets approved. You would still have the basic approval in place for economic or reliability reasons.

It's fundamental in that it hasn't been viewed this way before, but I don't think I would characterize it as completely turning over all the tables. And it is just a way to find new creative ideas.

I also agree with Mr. Avery that it's a parallel track effort and there's absolutely no intent or -- we don't believe and we don't wish for this to be a delay. If anybody feels that that will happen, you know, we need to hear everything. And I'm sure we'll hear it all tomorrow.

But I just wanted to kind of

recategorize what our effort at FERC would be. I don't think it's turning over a bunch of tables.

MR. FERGUSON: If I can just comment. The current plan that's now being looked at by the ISO, I think, for Tehachapi, I think, avoids the issue. If they proceed with the current top plan. I mean there's a lot of them. But it's almost certainly network, the network connection. And probably avoids that.

There's a perception from a lot of us, I think, that although the PUC did sign on the decision about the use of 399.25, there are still some problems about how that would be applied.

And there's a feeling that the PUC would like to avoid having to invoke that clause if at all possible. Perhaps you'd like to comment on that, if you would.

ASSOCIATE MEMBER GEESMAN: Let me possibly get at it --

COMMISSIONER BOHN: Can I have an alternate question?

(Laughter.)

ASSOCIATE MEMBER GEESMAN: Nancy, it was just a couple years ago that a different Southern California Edison successfully persuaded the State

District Court of Appeal that this area was preempted by federal law.

What would keep say a disgruntled PG&E customer all of a sudden facing a spread of Edison-related transmission costs under 399.25 from finding those old Southern California Edison briefs and making the same pleading in front of some other court?

MS. RADER: I wish my attorney were here. I think they're different issues. The issue in the court case was whether the PUC could direct the utility to file at FERC to finance the line. We agreed that the PUC's decision was poorly worded. What it should have said was that the PUC would order -- no, I'm sorry, the court said you couldn't -- they could not order the utility to finance the line directly.

And we felt that the PUC should have said, we order you, Edison, to go to FERC and file to finance the line. And the linkage was to direct the PUC and ordering them to -- clearly what was not a jurisdictional.

This issue, though, is entirely different. It's whether the state wants to provide the utility with assurance that if it volunteers to finance the network upgrade, that we will pay it back if the generators don't show up.

It's really a voluntary, it's completely voluntary. And it doesn't step on any jurisdictional toes. I think the issues are entirely different.

MR. FERGUSON: Other comments? Would somebody from the audience like to comment? I mean this is an issue we're going to be discussing at length tomorrow, so the more suggestions we got going in, the better we like it.

My own feeling is that it's a matter of states' rights. I think we ought to make it a states' rights issue. The ISO is now, you know, thoroughly engaged, and happily so, with the renewable program.

And my feeling is if, you know, collectively we decide that this is a needed part of the grid to implement our program, the state ought to have the right to do that through the usual cost recovery tariff mechanism, and that the federal government has no business telling California what it can and cannot put in its tariff.

I got to thinking about the whole issue

of proactive planning. And, you know, basically you heard the usual reasons that we can build a line and put it in the tariff, and they're all reactive. I mean, you know, if a generator comes and wants to interconnect, then, you know, we can figure out what they need and allow them to build the interconnection facilities.

Or if, you know, the grid gets congested we can wait until it does and then relieve the congestion. Or if it becomes unreliable we can, you know, make it more reliable. But they're all reactive.

And what everybody's been talking about, the big mantra now is that we need to do proactive planning. We need to get ahead of the curve. When you stop and think about how you're going to do that, how are you going to know what to build.

Well, you've got load forecast, you know, we have some idea of what the loads are going to be ten years down the line. But that's only half the equation. The other half is you got to know what supplies you're going to want.

And, you know, if you're going to do proactive planning you're going to build transmission lines to where you want to get your supply out of. And, you know, basically that's what we're trying to do at Tehachapi and, you know, that would be the use of this option, if we get it, from FERC.

So to my mind, I mean that's really sort of the issue. Is FERC going to let the states do proactive planning? Are they going to let the Western Governors plan a line up to Wyoming to get coal and wind out of Wyoming? Are we going to build at Tehachapi, you know, on and on.

I mean, even Palo Verde-Devers, I mean that's a goal to be able to access generation in Arizona. So, the only difference is that theoretically the trunkline proposal, the power only goes one way. And at least theoretically sometimes California could be sending power east to Phoenix or someplace on PV-D-2.

But anyway, personally I think we ought to get it out of the realm of sort of legal nitpicking and try to present an image of what it is that we're trying to do. And, you know, argue that, you know, as a state we ought to be able to have the right to do that, and to use the tariff like an ordinary project. Anyway, now I got my editorial in.

ASSOCIATE MEMBER GEESMAN: I think that's more compelling on a political level than on a legal level, because I think the ISO is a federal regulatee and actually has better standing with FERC than a state government would.

I think the other -- the FERC Commissioners may respond to your states' rights arguments, but I suspect the FERC Staff and ALJs would look at the ISO as a more compelling applicant than state government.

MR. KELLY: Two prong, two prong. My sense is that there are mechanisms to provide assurance to the regulated utilities for cost recovery today, as the backstop.

I mean I -- so I wouldn't want any transmission construction to be delayed while this FERC thing is played out. FERC's policies have a lot of important principles; it's a national policy; there's a lot of history there which is, quite frankly, going to be difficult in many cases to change. And I think we found that in the trunkline proposal, that there are reasons why FERC decides what it wants to do.

In this case, this fight at FERC, or debate at FERC could take some time, up to a year.

And I'm hopeful that we will move forward with the needed transmission during the interim while that works itself out.

And once they determine the cost recovery mechanism then we can deal with it. But we shouldn't be an impediment to building the infrastructure.

MR. AVERY: And, again, I don't believe it is. Even at Tehachapi I don't believe it is.

MR. FERGUSON: There were two other questions, to move on, we're running a little late here. There was a question about the TRCRs, the transmission cost ranking reports. And kind of a related question about how to modify the current transmission interconnection process so that the new additions to the grid -- new generators can get access.

The two are very much related, and we can talk about them together or separately, if you want.

But, you know, the issue on the TRCRs, and we have argued on behalf of CEERT at the PUC about this issue, is that the question is what assumptions go in when the TRCRs are prepared. And the argument is that, you know, basically the utilities are treating the new generation as if it's in addition to everything that they are now buying.

And for example, you know, if a generator from southern California is going to want to use the line, Path 22 -- Path 15 south to north offpeak. Since that's already congested, well, we're going to have to build another upgrade to Path 15. And therefore the cost of that upgrade,t he next upgrade is going to be held against the generators in southern California that want to bid into a PG&E process.

And, you know, our argument is that that's not the way the grid works; it's not the way the grid is dispatched. And that to require a Tehachapi generator to upgrade Path 15 is patently ridiculous. So we go round and round. In the end, the ALJ at the PUC says, well, PG&E says this and you guys say that, and I don't know what the answer is, so we'll just stick with the status quo. And there we are.

I think question number 8 is pretty much related, because the assumption is that, you know, Path 15 is congested -- and I'm just picking on Path 15 because Chifong Thomas beats me over the head with it every day. But it is the same kind of argument, that they're already users that are sending power up north on Path 15 offpeak. And by golly, nobody else gets to use that. Certainly not a Tehachapi generator because it's already in use.

And so the way you look at it is sort of, you know, the TRCR is the end result. And to tell you the truth, I don't know enough about the rules at the ISO work, how they work, but clearly these are a problem. And I think that the staff is looking for some guidance about, you know, ways to deal with this and maybe change the current TRCR process, or at least change the way, you know, maybe get an outside evaluator to evaluate the things and see if they're accurate reflection of reality or whatnot.

Would the ISO like to comment on this first? Dave, Robin? How are you going to ask a good question if people don't want to answer it.

MS. SMUTNY-JONES: I'm not capable of addressing the transmission interconnection question, so I don't even want to try. Dave, is this the right group of people sitting here?

I think maybe we need to table that for

tomorrow, a side discussion.

MR. FERGUSON: Anybody want to --

MR. AVERY: I'll be happy to address it. This becomes perhaps more of the chicken-and-the-egg syndrome again. To the extent that I have a contract with a renewable developer and that contract makes sense to me, then any ancillary transmission that's required in order to facilitate that's going to be taken care of.

It's either going to be taken care of from the standpoint of the network upgrades that I make, or it's going to be taken care of by generator interconnect facilities that the developer takes care of.

And if there are third-party upgrades required on Edison's system because of part of this, then in the process that we go through, the facilities may be advanced by the developer, but they're going to be refunded when they go in service.

And I have not encountered any problems with any of the generators that I've been dealing with with respect to this.

MR. FERGUSON: But I think the question is do the existing users of the line, whether it's

SWPL or Path 15, do they have a right in perpetuity to that line that prevent a new generator from using the line that require the upgrade, no matter who builds --

MR. AVERY: Well, you have to keep in mind that, first off, they do not have an exclusive right to those assets. They don't have any kind of historical right there, other than some contracts that exist under the ISO that deal with existing transmission rights.

But of the ISO-controlled facilities, those facilities are open for the use of the ISO customers. Now, if it relates to a new generator that adds congestion to the system, and a network upgrade is required, that network upgrade is ultimately made by the utility, or perhaps a merchant transmission entity.

And those facilities are reimbursed at their network upgrade cost. They are not borne by the individual wind developer or geothermal developer or anybody else, for that matter. So they should not be viewing this as an obstacle towards the development of those types of resources.

MR. FERGUSON: Other comments? Nancy.

MS. RADER: Well, it has been an obstacle, for example, between PG&E and Tehachapi,, where the entire cost of a Path 15 upgrade was being tagged, was being charged to -- in a bidding evaluation process, to the renewable generators. Even though that upgrade would have many other benefits beyond accommodating that generator.

MR. AVERY: But you're not suggesting that that generator then had to bear that cost. Those costs became network upgrades --

MS. RADER: Right. It's just in the bid evaluation stage --

MR. AVERY: And I think that's -- I think that is part of the process for looking at any development. If any utility or any LSE has an opportunity to secure a megawatt from one developer and a megawatt from another developer, and one of them requires no network upgrades and no additional costs, then that is the way the evaluation is done.

If another one requires massive upgrades in order to accommodate it, then it has to be looked at --

MS. RADER: I agree, I --

MR. AVERY: -- into the overall picture.

MS. RADER: I agree. The problem is that we were being given all the costs without recognizing that there are benefits to other people for which we are not getting credit. In other words, there was no netting of the benefits associated with the cost of that line.

But let me just say that I think we have a work-around; we got work-around just before PG&E's 2006 procurement plan was finalized, where PG&E agreed that it would use the lesser of that bid adder, or the cost of remarketing the power from southern California to, you know, elsewhere.

So, I think we do need to fix the TRCRs, but we do, I think, have a work-around that should be good for any area as long as you can get your power into the ISO grid.

MR. KELLY: It sounds like we're talking about two things. One, bid evaluation; and then actual transmission access. And those are very different animals here.

I think in terms of the transmission access that the Path 15 is a good example of why the concept of a RECs is helpful because you avoid this issue as long as you can integrate into the grid in southern California. And then you've got a RECs trade with PG&E in northern California. You can facilitate this and it doesn't place the burden on the next incremental generator, I think.

MR. FERGUSON: Well, I guess I'm still not understanding. I mean I understand the bid evaluation process, which is what the TRCR is used for, but I guess I still don't understand this issue that well, the line is full and therefore you can't interconnect.

I mean when somebody applies for interconnection they don't need to tell who their contract is with. They don't even have to have a contract. So, in principle, somebody from Tehachapi could interconnect without knowing whether their power was going to be sold north, south, east or west. And, of course, the power doesn't follow the money anyway.

So, I'm still scratching my head about this question number 8. That to the extent that the current transmission users can prevent new entries. But you say it doesn't happen?

MR. DASSO: Yeah, I just want to add onto that what Jim had said, it really doesn't prevent that as part of an overall evaluation of, you know, the total cost of a particular -- I mean it's really to help determine what is the total cost of a particular bid for evaluation.

It doesn't prevent the entry of a, you know, individual project. And, again, as Nancy mentioned, it's really around how do you go about considering those real transmission congestion issues, and how you go about evaluating bid.

The primary aim behind the TRCR was to provide transparency into where is it less costly, or least impactful on the grid to connect generation. And also to help guide the overall, you know, total cost of potentially a potential bid.

It doesn't, you know, when you take it down to the individual generating unit, that cost of Path 15 is not going to be, -- you know, a Path 15 upgrade is not going to be placed on that generator to deal with.

And, again, it doesn't prevent that individual generator from coming online. It's really more a matter of helping understand the total cost and total impact of, you know, where the generation's being located.

MR. FERGUSON: Dan.

MR. ADLER: Let me just ask maybe a clarifying question. Take an isolated incident with one new renewable generator being added to a full line. Why, as a matter of state policy, would that new renewable generation not get priority such that some existing fossil generation is bumped off, as a matter of policy?

MR. FERGUSON: Well, as a matter of law, I mean --

MR. AVERY: Well, I think actually it's a matter of FERC regulation that does not provide for that. Everybody is afforded an equal and open access to the grid.

And to the extent one new generator comes on, he's not afforded the opportunity just unilaterally to bump another generator. However, from an economic dispatch standpoint, renewables are dispatched first.

And so, I mean, in reality, from an economic standpoint, the older, less efficient fossil plant is essentially congested because of the new renewable resource.

And the same thing would happen if a new combined cycle plant located on top of an older, less efficient power plant. They would, in essence, bump them in the economic queue and the congestion would be realized by the more expensive, less efficient generator.

But from the standpoint of just giving priority, federal law preempts that. Federal law does state that you cannot give a unilateral right to one entrant to bump another one. But economics does it by default.

MR. ADLER: Because that seems to be hidden within question number 8. This notion that the loading order can somehow trump federal law in that regard.

MR. DASSO: The other thing I wanted to add is also as you look at the impacts of where the generation is being located and how that affects the TRCR, it provides guidance in terms of where you ought to be making transmission upgrades.

And I guess one of the points that we wanted to make is that there are several upgrades that have become very apparent going through the RFO process. As Fong mentioned, sort of using the RFO process to really guide where it is that you ought to be building transmission.

So, there are, through that process PG&E

has identified several upgrades in the northern part of the system to access renewable resources in the northern part that are relatively low cost, and, you know, easy to do; relatively short time period, you know, two to three years type of thing, with substantial benefits.

Without some starting point in terms of where are your congestion points and where are your actual resources, you're kind of shooting in the dark in terms of where you should be pursuing your transmission upgrades.

Specifically one of the other projects that we proposed in our expansion plan was a project called Midway Grade, which essentially addresses some of this congestion issue on Path 15 from the south-to-north flow. It also addresses reliability issues in the Fresno area. And it also addresses reducing reliance on reliability-must-run generation.

So, again, using this type of tool we can target where our expansion ought to go. And that was kind of the aim. It was also to provide some information to the generator in terms of where are easy places to go where you're not going to run into these congestion issues.

ASSOCIATE MEMBER GEESMAN: Have the TRCR cost estimates been an accurate predictor of ultimate upgrade costs?

MR. DASSO: From our perspective it's really kind of a relative. It's really designed to be relative. So, --

ASSOCIATE MEMBER GEESMAN: The best information you have at the time.

MR. DASSO: -- to the extent that they're based on unit costs or maybe generic reconductoring or line construction, they are applied uniformly to all of the proposals that are being evaluated.

So, they do, from a kind of a generic perspective, provide a relative cost.

ASSOCIATE MEMBER GEESMAN: But you haven't had enough experience with them to actually have an empirical database that would tell you whether they're an accurate predictor of what the ultimate upgrade cost is or not?

MR. DASSO: No, because again often, you know, when you actually get down to it, you have to really study the individual project. And ultimately you have to look at the specific interconnection facilities that are necessary for that particular project, for that particular time, with that particular position in the queue.

So, you know, at the end of the day you have to look at it project-specific. But, again, it does provide a good relative perspective.

MR. AVERY: The only thing I was going to add to that is if you look at what's been happening to the steel market, no estimates that have ever been created --

MR. DASSO: Sure.

MR. AVERY: -- are ever all accurate.

MR. DASSO: Sure.

MR. KELLY: Dan, if I could respond to your question from a developer perspective, I mean one of the things that developers want when you're about to drop $250 million into an investment is some measure of regulatory certainty; your ability to get your product to market.

And if the renewable developers thought about this for a nanosecond, you know, today the renewables are preferred against gas; next year it's going to be geothermal versus wind. And the year after that it's going to be geothermal from point A versus geothermal from point B.

And that kind of priority is problematic for people to try to develop very expensive projects. They want to see some measure of certainty. And the FERC rules actually provide some of that.

MR. AVERY: I'm looking forward to the day when we're fighting about which renewables we get to take.

MR. FERGUSON: I'm not so sure we're that far away, Jim.

(Laughter.)

MR. FERGUSON: We should talk about those Stirling contracts.

(Laughter.)

MR. TAM: My name's Gil Tam; I'm the Director of Contracts with Southern California Edison, responsible for interconnecting all the generators in our grid. And I can't fly 300 miles, 400 miles up here and not say something, I guess.

(Laughter.)

MR. TAM: I just wanted to maybe add some clarity to it. I think a lot of you probably got it. There's two issues here we're talking about. One is interconnection of a wind generator to our grid. And then also dispatching resources.

Interconnection to the grid is based on a queuing process that is dictated by FERC. And in order to connect a generator they must relieve any congestion or system reliability concerns. And they would have to fund the -- provide upfront funding of the transmission upgrade. And then within a five-year period then they get reimbursed back. So in essence the IOU or utility, through the TAC rate recover those costs.

Once they're connected then dispatching is basically, I think someone already talked about, basically whoever's the low cost and bid into the ISO and get the energy generated and produced, and so.

So, I think, I just want to make sure that point is clear. So, once you're connected, there's no FERC regulation to prevent anybody selling the energy to the market; depends on who's the low-cost provider. Just wanted to --

MR. FERGUSON: Well, let me throw this question out. Are you all in agreement that the TRCR should only reflect costs that are required by the ISO for interconnection? Cost the facility that are required by the ISO for interconnection.

MR. TAM: I don't think that's the issue

right now.

MR. FERGUSON: Well, I mean, are there other costs --

MR. TAM: You mean the network --

(Parties speaking simultaneously.)

MR. FERGUSON: -- put in your TRCRs that are other than costs that are required by the ISO for facilities to interconnect.

MR. DASSO: The ISO reviews all of those -- reviews that specific interconnection plan. So, if we -- ultimately we come to agreement with the ISO as to what it is that's necessary in order to connect that particular generator.

MR. FERGUSON: What I'm saying is it only those costs that should go into TRCRs.

I mean the Path 15 upgrade would not be required of a Tehachapi generator merely to interconnect to the grid, for example.

I mean I'm just trying to get some principles about what these TRCRs should be doing.

MR. DASSO: Yeah, again you're sort of mixing issues, I think. And the TRCR was intended to provide a picture of the grid as it exists today for purposes of evaluating incremental new generation connecting. And that was the purpose, intended to provide some transparency for developers as well as the utilities for evaluating overall costs for bids.

However, the specific project, you know, has to be looked at on its own merit when you're looking at the actual interconnection cost.

MR. KELLY: But I think -- is it the interconnection at the buss bar, or is it what it would take to deliver to, for example, a load center?

MR. FERGUSON: Which brings in the whole question.

MR. WAN: Because I think you're asking a question that crosses over to bid evaluation, selection process --

MR. FERGUSON: It's the TRCR --

MR. WAN: -- not just the transmission upgrade. If PG&E is evaluating a Tehachapi project what we are supposed to do with that power is to wheel it to northern California or central California to serve our load.

And because of that wheel we have to consider the Path 15 upgrade. We currently don't have a program where I can dump the power somewhere else and take the RECs with it. That's part of the issue.

Now, to answer your question directly, we use this TRCR for the short list evaluation process as to whether we will sign this particular contract; we are still carefully looking at the topic you brought up.

MS. JONES: Can I ask a clarifying question.

MR. WAN: Yes.

MS. JONES: When you do TRCRs when evaluating the RPS bids. Do you use TRCRs in evaluating all-source bids?

UNIDENTIFIED SPEAKER: Don't think so.

UNIDENTIFIED SPEAKER: I can answer for us.

(Laughter.)

MR. PIZARRO: We're back. In the case of SCE I think, like Fong was saying, we view the TRCR as a tool that's really been developed for renewables. And it helps expedite the process. So that's a lot of the value. You don't have to wait for all these system impact studies, et cetera, to make a procurement decision.

So frankly that's an advantage that we're conveying to renewables in our process. I think part of providing the rebuttal presumption and preference.

In the case of our all-source, for example, with a new generation RFO that we expect to launch shortly here, assuming a final decision from the PUC, we will not be using TRCRs, but in fact, we'd be relying on full studies out of the ISO prior to our signing contracts.

And in fact, that's what we have a faster condition for contracts that are already -- for projects that are already down the path of the interconnection process, -- permits in hand. But we have those studies available and can incorporate them in our bid evaluation versus our standard tract, which will take longer -- for projects that would be more greenfield or earlier in the process, and we'll need to go through the ISO application process interconnection queue and the development of those studies.

So, I don't know if that helps from an SCE perspective.

MR. FERGUSON: So you're saying the TRCR, so you're a proxy for --

MR. PIZARRO: Yes, it is a proxy --

(Parties speaking simultaneously.)

MR. PIZARRO: That's right, it is a proxy and it helps to facilitate the speeding of the renewable process.

MR. WAN: Melissa, in terms of all-source solicitation, we actually went through a much more rigorous program. We asked each of the bidders to commission a system impact study with the grid side of the business. And that study is done by us. And then also approved by ISO. So it is an exhaustive study before we would actually commit to that.

Whereas the renewable program, as we just described, we're trying to shortcut part of that.

MR. FERGUSON: Okay, we need to move on here, we're running late. But, so I think we understand how the TRCRs are used. But, it brings back this question about what all should go into it, because what you're saying is it's not all just a question of interconnection, but it's also the cost of relieving constraints should also go in the TRCRs. And that's where we part company.

Everybody, we would agree, I mean I think everybody would agree that, yeah, the interconnection costs have to get rolled into the bid price one way or another.

But this whole question about, you know, because there's a constraint on the line and you want to transport power across that line, then you're responsible for upgrading the line, is not how the ISO works to relieve constraints.

I mean at most you can say, well, it's going to go into the ISO constraint relief process, and you know, INCs and DEC bids, or whatever the hell they're using these days.

So, it is a really sore point for the generators about, you know, what, you know, about how congestion in the grid affects your ability to absorb a new project. And what they would have to do to, you know, to solve that congestion.

So, this was a great question that was on here. I don't think we have time -- be happy to respond, but --

MR. AVERY: Yeah, unfortunately I have to leave, but I just want to give one comment on that.

As it relates to network upgrades, as those are made, to the extent that a generator had funded any of that, they are returned that money plus interest. And so it has not, in our experience, hindered the development of any of that generation.

So to the extent that we had a project that required an upgrade of Path 44 or Path 43, and we made the decision to go ahead with that, we may make the case that that is something that is required in order to facilitate that project we'd pursue it, ourself. Or if a generator was going to advance it, they would be refunded that money once they went into service. And, again, I don't think that jeopardizes the project at all. So there's ways to do it.

MS. JONES: So, let me ask a question now. It could kick a bid out of being selected because of the total cost of the bid. So, that bid would never get to be a project and would never incur any costs.

MR. AVERY: In the bid evaluation process I can tell you that we have had some projects that the network upgrades that were required were very very extensive. So, what we've tried to get through to get around that is to look at ways that perhaps helping them identify a different way or different location to locate.

But if it's going to take $400 or $500

million to connect a $50 million wind project, it probably shouldn't be selected, if that's all that could be developed there.

MS. RADER: Can I just say again that I think as a practical matter this isn't a big issue, at least for interzonal transfers, because of the PUC decision that says the utilities can take delivery outside their service territory, remarket the power and keep the credit. We won't call them RECs, we'll call it the credit.

So, as a practical matter the TRCRs aren't that much of a bid deal. I mean we still don't like them, but as a practical matter if you bid to deliver in a different service territory, you should be evaluated accordingly and not be tagged with the bid adder.

(Laughter.)

ASSOCIATE MEMBER GEESMAN: Who's next?

MR. ADLER: Let me take this opportunity to make a different point about transmission. Since I've sat through a TRCR conversation, I think I'm entitled.

It's also, the transmission system is also a tool for technology development. It's clear that where we are today with our renewables portfolio, we're going to use these technologies for the next four or five years. What happens next?

And from the standpoint of what you can call the first megawatt problem, it's very important that new technologies, be they concentrating photovoltaic or vertical wind turbines or new biomass technologies that are coming along, that the RPS program embrace them and give them the opportunity to demonstrate for the marketplace that they work; the first megawatt can run; can produce up to performance standards for a full year. And then those entrepreneurs and technologies can get project financing and become the next generation of large-scale renewable projects that we're going to need in the outer years of our stretch goal.

So, somewhere in the grid planning process there should be a little carve-out for technology demonstration if we're going to hit our long-term goals.

MR. KELLY: Why isn't that a PIER program thing?

MR. ADLER: That's an excellent point. I think it should be; I think it increasingly is.

They do demonstrate --

MS. SMUTNY-JONES: Dave is croaking over here that it is.

MR. ADLER: They do demonstration finance. The question is, is that demonstration finance tied closely enough to the year-long performance data that is then bankable. I'm not sure it has been in the past. But I think that the PIER program is now more attuned to that as a market support mechanism.

MR. FERGUSON: Since Calwell isn't here, I think we can take up question 7. Strategies to address the current ISO interconnection queue process which may be preventing successful renewable generation projects from being constructed.

This is a hot-button issue, but there was an accusation that there were some people in the queue who did not have contracts, and that somehow they were occupying queue space that should otherwise be forfeited to projects that already have utility contracts.

Since PPM Energy has a project at the front end of the queue without a contract, they were feeling especially -- is this a problem, or is this not a problem that we need to deal with?

Robin? Dave?

MS. SMUTNY-JONES: I think we don't believe it's a problem. And others may have other opinions, but tomorrow we will have the right folks from the ISO that can, in a very detailed fashion, address these kinds of questions, the queuing questions in the interconnection process.

MR. KELLY: Well, I guess I'll take this up tomorrow, but it seems to me that we need to look at whether or not there are some semblance of milestones as you sit in the queue.

I mean if the interconnection costs are a function of everybody in front of you that might be sitting there latent, as it were, we need to figure out a way to make sure that the viable projects can move forward in a timely manner.

So, I don't know what your process has today for that, but there needs to be some discussion of that, I think.

MS. SMUTNY-JONES: Yeah, one point that he's channeling to me -- one point that Dave makes, which is a good one, is that that's part of what motivates the ISO to do a more comprehensive plan and look at the grid.

MR. FERGUSON: Did he just say something else?

(Laughter.)

MS. SMUTNY-JONES: No, just the southern California and the northern California sort of regional, looking at things all together to see what makes sense, rather than just one at a time.

MR. FERGUSON: Are there people in the room that think this is a big problem that needs a solution? I don't know where this ever popped up, to tell you the truth. But it was kicked around.

The last question was focusing state research and development efforts on issues surrounding wind integration basically.

And there are a whole bunch of projects going on, so I'm not quite sure what guidance the Commission was looking at when they asked this question, but Dave has been working on this problem for a year or more. And we haven't killed him yet --

MS. SMUTNY-JONES: Yeah, look what happened to him.

(Laughter.)

MR. FERGUSON: And I know the Commission also has a project under contract that's now ongoing. So, somebody want to comment on this question? Is this -- I know it keeps coming up and, you know, the question about how much ancillary services are going to cost. You know, if we have 4000 megawatts of wind in Tehachapi turning on and off every couple hours, you know. Anybody want to comment on that? Robin for Dave?

MR. HAWKINS: I'll give it a try. The research -- I can't do it -- research --

MR. FERGUSON: Totally agree with you, Dave, that was excellent. Well spoken.

(Laughter.)

MS. SMUTNY-JONES: Okay, I think what he's trying to say is that this requires a lot of research and there needs to be a lot of focus on studies that take a good look at what are the consequences of wind integration.

I can say, from a policy perspective, the ISO sometimes is the skunk at the party to say there's all these issues that happen and you need regulation. We'll probably still come and say that, but I can also say that we're very committed to overcoming whatever those issues are, and we feel confident that we will.

ASSOCIATE MEMBER GEESMAN: Yeah, we're

committed to funding a lot of research in this area. We recognize this problem is not going to go away in a couple of years. We've got a lot of research underway now, but we envision continuing it for a number of years.

MR. FERGUSON: And there's an upcoming workshop, I believe? You might want to --

ASSOCIATE MEMBER GEESMAN: Yeah, I don't know the calendar. Dora, when is that?

UNIDENTIFIED SPEAKER: August 15th.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. FERGUSON: August 15th, okay.

UNIDENTIFIED SPEAKER: In the same room from 9:00 to 5:00. And (inaudible) to talk a little about that.

MR. FERGUSON: Everybody get that? August 15th, all day here, to talk about wind integration.

UNIDENTIFIED SPEAKER: We'll try to end it at 5:00.

MR. BESHIR: I just wanted to mention from LADWP's perspective, we have not really engaged in the major research aspect, but some of the wind projects we are looking at at the Tehachapi are going to be integrated with a transmission system which already carries hydropower plant. So we do see a big marriage or synergy integrating wind with hydro plants.

And we are working on a control mechanism to see how we can play wind with the hydro, which has some reservoir capacity, so that we, for one, would be able to (inaudible) the wind.

Second, we also utilize the transmission in a more equitable or more efficient manner. Thirdly, DWP has a large pump storage facility. And, again, we are looking at integration of that system with a wind project we are building today. And also some wind projects we are looking forward.

So, in the future I think there may be some things we're going to probably offering in that area as far as from a practical manner.

MR. FERGUSON: Thank you, Mohammed. Since you brought up the Castaic pump storage, I suppose we should put in a plug for the LEAPS project which we've also been looking at out at the ISO.

It's a project in Orange County, I guess, that the ISO would very much like to have.

the problem is the developers can't find a buyer. And the reason is pretty simple, and that's that we have no idea what the revenues to a pump storage project would look like down the road.

So, it's about a what, $750 million project. And that's an issue that the Commission might well take a look at, is, you know, if it's not -- it would be enormously valuable to the grid. Dariush wants it badly. But if it's not commercially viable because of the current structure of ancillary services markets and so on, how do we make up that disconnect.

As Dariush says, if he owned the thing and got to run it, he would actually destroy the markets for ancillary services.

So, there's a little bit of a conflict here between facilities that would really support the grid and help renewables and all the rest, and the current market structure that we have for ancillary services.

So, that would be an interesting topic for the Commission to spend some time thinking about.

Any other comments? Any other questions people want to raise? Or shall we all go have a beer? Question, or should --

MR. BRAUN: My name's Tony Braun; I represent California Municipal Utilities Association. And in the vein of attempting to make the meeting constructive tomorrow at the ISO I thought I'd throw some issues on the table in a point of clarification, and also to help the ISO think about things overnight.

I agree with the way that Edison and PG&E representatives distinguish between the operational and dispatch elements of wind and the procurement and interconnection elements of wind. I'd, unfortunately, like to add a third element which is directly relevant to recently adopted state policies, and that is capacity counting.

As we all know, we have a resource adequacy policy in various venues whether it's adopted by the PUC, adopted through the State Legislature, or adopted by our city councils. And this involves capacity counting to meet prudent planning reserve margins.

The ISO tariff currently has mechanisms for measuring deliverability, whether that's deliverability of imports or net deliverability aggregate of grid for those generation units that are inside the control area.

So I'm suspecting that when load-serving entities invest in these resources, recognizing that they're probably, for certain of them anyway, not high capacity resources, nevertheless are going to want some measure of trying to know how to count them for capacity.

The ISO's rules, reasonably, because units don't do us a whole lot of good if they're not deliverable, discount for units that aren't deliverable to the grid.

So how we're going to measure interconnection policies and these are newly adopted and uniform, frankly, fairly uniform resource adequacy rules that are implemented through the ISO tariff, I think, are very important.

A second issue that I think the ISO, it would be helpful to consider overnight, is the mechanisms for how costs are allocated in the TAC are complex. And they're not as simple as we get high voltage new lines in one way and low voltage in another way. And new facilities get rolled in and spread statewide.

There's actually something called the

cost-shift cap. And when new facilities are proposed by certain entities that aren't the original participating transmission owners, they're treated in a manner differently than if they are proposed by the existing -- the original three participating transmission owners.

So you could have a situation if you go through one of the three, or two of the three, I believe, cost allocation mechanisms that are outlined in the whitepaper, a different outcome depending on who the sponsor of the transmission is. So I think that's something that needs to be considered.

And, third, I'd like to throw out the equitable nature of how this is going to affect our partners in the rest of the western interconnection. Right now it's not just California entities that pay the ISO's transmission costs. It is entities that use the ISO-controlled grid, and that is a very wide subset of entities throughout the western United States.

And what we will be asking them to do, if we do put the cost of these facilities into the TAC, is to help pay for our state policies.

So, as --

MR. FERGUSON: If they want to use our grid.

MR. BRAUN: If they want to use our grid. And we hope that they do, or we'll have bigger problems than meeting our RPS.

So, when we go forward and consider these things, perhaps those are issues that can be discussed more fully tomorrow. Thank you.

MR. FERGUSON: Thank you, very good. I have word that Kevin Porter is on the phone and would like to speak to the wind integration issue.

MR. PORTER: Thanks. I understand Dora is in the room and she just provided you an update on the August 15th workshop. So I think that issue is now moot.

I just did want to point out that someone mentioned this is just a wind integration task. We're looking at all renewables and solar will be definitely a part of it, especially with the Stirling solar project and the solar initiative that was spoken of earlier. So that's something we'll be looking at as part of that.

I do want to say that we do have a monthly call that we -- well, obviously we do every month, that we update people that want to participate on the call on the status of the project.

I had to reschedule the call; it will be sometime next week. If people want to contact me directly to find out how to get on that call they can do so at porterassociates.com, or they could ask Dora, who I believe is still in the room.

Thanks a lot.

MR. FERGUSON: Okay, I didn't mean to pick on the wind guys, I apologize.

MR. PORTER: Don't worry.

MR. FERGUSON: John, I think I'll turn it back over to you, then.

ASSOCIATE MEMBER GEESMAN: Well, I want to thank everybody for your contribution to what's been a very content-rich afternoon.

Pam, can we give people a little bit of relief on the deadline for written comments? We had it originally posted as tomorrow, and I'm wondering if we can spread that over to next week sometime without --

MS. DOUGHMAN: Sure, that'd be fine.

ASSOCIATE MEMBER GEESMAN: Why don't we make the deadline for written comments next

Wednesday, which I believe would be July 12th.

Again, I thank you all for your participation and look forward to our next workshop on this topic.

(Whereupon, at 5:32 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 18th day of July, 2006.